COST OF SERVICE SUMMARY

1.0 INTRODUCTION

This evidence presents an overview of Hydro One Transmission's Cost of Service. As summarized in Exhibit C2, Tab 1, Schedule 1, the Cost of Service includes the following elements, for which the overall costs for 2011 and 2012 are shown in Table 1 below:

- Operation, Maintenance and Administrative ("OM&A") Expenses,
- Depreciation and Amortization Expense,
- Capital Taxes, and
- Payments in Lieu of Corporate Income Taxes.

Table 1
Costs of Service ($ Millions)

Line no.	Description	Test Year	
		2011	**2012**
1	OM&A	436.3	450.0
2	Depreciation and Amortization	302.9	334.8
3	Capital Taxes	-	-
4	Income Taxes	80.9	70.0
5	**Total Cost of Service**	**820.2**	**854.8**

2.0 KEY ELEMENTS OF THE COST OF SERVICE

Hydro One Transmission's forecast cost of service has been developed consistent with corporate strategic goals to sustain a safe and reliable transmission system that economically meets customer needs and provincial policies, as noted in Exhibit A, Tab 11, Schedules 1 and 2. The Company's planning process is described in detail in Exhibit A, Tab 12, Schedule 1.

2.1 Operation, Maintenance and Administrative Expenses (OM&A)

Total OM&A expenses for the 2011 test year are $436.3 million and for 2012 are $450.0 million.

Hydro One Transmission plans and organizes its OM&A expenses on the basis of the various work programs and functions performed by the Company. These work programs primarily address improvements in infrastructure and improvements in productivity and efficiency. Exhibits in support of OM&A costs have been prepared by function, and appear within the submitted evidence as follows in Table 2:

Table 2

Particulars	2011 Total Cost ($ million)	2012 Total Cost ($ million)	Reference
Summary of OM&A Expenditures	**436.3**	**450.0**	**Exhibit C1, Tab 2, Sch 1**
Breakdown by Function:			
Sustaining	233.0	243.1	Exhibit C1, Tab 2, Sch 3
Development	18.2	18.9	Exhibit C1, Tab 2, Sch 4
Operations	66.3	68.2	Exhibit C1, Tab 2, Sch 5
Shared Services	46.9	46.4	Exhibit C1, Tab 2, Sch 6
Customer Care	1.1	1.2	Exhibit C1, Tab 2, Sch 12
Taxes other than Income Taxes	70.8	72.2	Exhibit C1, Tab 2, Sch 13

2.2 Depreciation and Amortization Expense

As part of its pre-filed evidence for its 2007-2008 transmission rates proceeding (EB-2006-0501), the Company filed the Foster Associates Inc. depreciation study. The Study's methodologies and associated cost flows were accepted by the Board in the subsequent Decision with Reasons. In 2008, Hydro One Networks engaged Foster Associates Inc. to update this study for the EB-2008-0272 Transmission Rates Application and ensure it was consistent with the Board-approved depreciation methodology. The results of this review form the basis of the depreciation submission in this Application. The Company is proposing to recover $302.9 million in depreciation and amortization expense in 2011 and $334.8 million in 2012. These amounts are driven largely by the rise in capital expenditures in the 2008 to 2010 period on development projects related to transmission system expansion to address load growth and incorporation of new generation, some of which are beginning to come into service, as well as sustainment of aging transmission station assets. Hydro One Transmission's evidence regarding the depreciation study and its impact on depreciation expense is filed at Exhibit C1, Tab 6, Schedule 1.

2.3 Payments in Lieu of Corporate Income Taxes

As a result of *the Electricity Act, 1998*, Hydro One Transmission has been required to pay proxy taxes since 1999. Evidence outlining the calculation of Payments in Lieu of Income Taxes of $80.9 million for 2011 and $70.0 million for 2012 appears at Exhibit C2, Tab 6, Schedule 1.

3.0 KEY COMPONENTS IN THE BUILD-UP OF COST OF SERVICE

Key components in the build-up of Cost of Service are:

- resourcing,
- costing of work,
- out-sourced functions, and
- corporate cost allocation.

Each of these components is discussed below.

3.1 Resourcing

Labour costs are charged to OM&A and Capital work programs. The evidence contained at Exhibit C1, Tab 3 presents total staff levels and costs incurred by the Company, as follows:

• Corporate Staffing	Exhibit C1, Tab 3, Schedule 1
• Compensation, Wages, Benefits	Exhibit C1, Tab 3, Schedule 2

3.2 Costing of Work

OM&A and Capital work programs are comprised primarily of costs relating to labour, materials and equipment. Exhibit C1, Tab 4, Schedule 1 provides a schedule that explains how costs flow to work programs. Throughout its operations, Hydro One Transmission has been successful in containing costs and employing productivity measures wherever possible. The Company's achievements in this area are presented in the following exhibits:

• Work Execution Strategy	Exhibit A, Tab 12, Schedule 7
• Cost Efficiencies/ Productivity	Exhibit A, Tab 14, Schedule 1
• Costing of Work	Exhibit C1, Tab 4, Schedule 1

3.3 Outsourcing

As a strategy to reduce costs, improve efficiency and to improve focus on its primary operations, Hydro One has entered into an agreement with Inergi LP to receive a range of services in the following areas:

- information technology,
- customer care,
- settlements,
- supply management,
- payroll and
- finance.

3.4 Corporate Cost Allocation

Hydro One Networks Inc. provides common services to its Transmission and Distribution businesses and to other Hydro One subsidiaries on a centralized basis, as this serves as the most economic approach. The costs of these services and assets are assigned to business units on the basis of cost causation. These costs and assets are directly assigned where it is possible to do so. All other costs and assets are allocated based on cost drivers, direct benefits or other methods as appropriate. Exhibit C1, Tab 5 describes these allocation methods, as well as the derivation of the overhead capitalization rate, which determines the assignment of overhead costs to capital expenditures.

In 2006, Hydro One Transmission commissioned R.J. Rudden Associates (Rudden) to conduct a cost allocation report for the Company's 2007-2008 Transmission Rates proceeding (EB-2006-0501). This was accepted by the Board as an appropriate methodology for allocating costs among the subsidiaries. Hydro One Transmission's evidence in this Submission reflects the same Rudden methodology. The Company's evidence in this regard and the accompanying Black & Veatch (Formerly R.J Rudden Associates) "Review of Shared Services Costs Methodology – 2010" is included as Exhibit C1, Tab 5, Schedule 1, Attachment 1.

SUMMARY OF OM&A EXPENDITURES

1.0 SUMMARY OF OM&A EXPENDITURES

The proposed OM&A expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place. This process is described in detail at Exhibit A, Tab 12, Schedules 1 through 7.

The proposed OM&A programs represent the work required to meet public and employee safety objectives, maintain transmission reliability at targeted performance levels, and to comply with regulatory requirements (such as specified within the Transmission System Code), environmental requirements and Government direction.

The development of asset maintenance programs, as described in the following schedules of this Exhibit, is based on equipment specifications coupled with comprehensive asset condition information, as well as information on asset demographics, component performance and reliability, and equipment utilization.

Hydro One Transmission's OM&A budget is grouped into different investment categories: Sustaining, Development, Operations, Shared Services, Customer Care and Taxes Other than Income Taxes. Table 1 provides a summary of Hydro One Transmission's OM&A expenditures for the historical, bridge and test years.

Table 1
Summary of Transmission OM&A Budget ($ Million)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Sustaining	205.9	187.5	213.5	224.4	233.0	243.1
Development	8.4	9.2	14.0	19.0	18.2	18.9
Operations	54.0	51.7	52.6	62.1	66.3	68.2
Shared Services and Other OM&A	80.9	59.4	70.8	58.6	46.9	46.4
Customer Care	1.2	1.3	0.9	1.1	1.1	1.2
Property Taxes & Rights Payments	62.5	64.8	65.2	69.4	70.8	72.2
TOTAL	**412.9**	**373.8**	**417.1**	**434.5**	**436.3**	**450.0**

Total OM&A expenditures for test year 2011 have increased by $2 million, or less than 1% over the 2010 bridge year. Total OM&A expenditures for test year 2012 increase by $14 million, or 3%, over 2011. The test year expenditures are required to address the increasing maintenance requirements of an aging and expanding transmission system.

The increased spending is primarily due to higher stations and lines maintenance sustaining costs, partially offset by increased Cornerstone savings captured in Shared Services and Other OM&A costs.

The increase in spending for 2010 relative to 2009 is primarily due to necessary increases in some station maintenance programs, initiation of smart zone Development work and Operations system support requirements, as described in the following exhibits, partially offset by a decrease in Shared Services and Other OM&A costs driven by increased overheads capitalized to support the larger core SDO capital work programs.

2.0 SUSTAINING

The Sustaining OM&A budget represents investments required to maintain existing transmission lines and stations facilities so that they will continue to function as originally designed. The proposed investments are intended to ensure that the overall reliability of the system is maintained, that customer commitments are achieved, and that all legislative, regulatory, environmental and safety requirements are met. Details are provided at Exhibit C1, Tab 2, Schedule 3. Details on Transmission Assets and Investment Structure are provided at Exhibit C1, Tab 2, Schedule 2, and Sustainment Planning and Investment Criteria are discussed in Exhibit D1, Tab 2, Schedule 1.

3.0 DEVELOPMENT

The Development OM&A budget funds research and development, as well as the development of new standards. The Development OM&A is described in detail at Exhibit C1, Tab 2, Schedule 4.

4.0 OPERATIONS

The Operations OM&A program represents the annual expenditures required for the Central Transmission Operations function, operated out of Hydro One's Ontario Grid Control Centre. The Transmission Operations function is concerned with the real time operations of the Hydro One Transmission system equipment, including the monitoring, control, detection and response to equipment operational issues. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 5.

5.0 SHARED SERVICES AND OTHER OM&A

The Shared Services and other OM&A program includes: Common Corporate Functions and Services, Asset Management, Information Technology, Cornerstone, Cost of Sales and Other OM&A expenses. The Common Corporate Functions and Services include the provision of financial, human resource, legal, communications, regulatory affairs, corporate security and internal audit. Asset Management programs include developing Transmission asset strategies, policies and standards; identifying, planning and prioritizing specific OM&A and Capital work on the transmission network; facility services; and monitoring the execution of the annual work program. Other OM&A programs include credits for overheads capitalized as capital projects are built and the cost of goods sold in support of external revenues. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedules 6 through 11.

6.0 CUSTOMER CARE OM&A

The Customer Care OM&A Work Program represents the set of work activities required to provide customer care services to the almost 1.2 million customers connected to the Hydro One Transmission and Distribution Systems. The main Customer Care service programs are meter reading, billing, settlements, customer contact handling and collections largely in connection with Hydro One’s distribution operations. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 12.

7.0 TAXES OTHER THAN INCOME TAXES

This program consists of property and proxy taxes, and indemnity payments to the Province. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 13.

8.0 COMPARISON OF OM&A COSTS TO BOARD APPROVED

Table 2 compares 2009 actual costs to the 2009 OM&A expenditures approved by the Board in their Decision on Hydro One Transmission's previous application in Proceeding EB-2008-0272.

Table 2
2009 Board Approved versus 2009 Actual OM&A Expenditures

OM&A Categories	**2009 Board Approved** ($ million)	**2009 Actuals** ($ million)	**Variance** ($ million)
Sustaining	211.5	213.5	2.0
Development	13.9	14.0	0.1
Operations	57.3	52.6	(4.7)
Shared Services & Other Costs	61.1	70.8	9.7
Customer Care	1.5	0.9	(0.6)
Taxes other than Income Taxes	69.7	65.2	(4.5)
Total OM&A	**415.0**	**417.1**	**2.1**

Hydro One Transmission's actual 2009 OM&A costs are $2 million higher than the $415 million approved by the Board in Proceeding EB-2008-0272. This is due to Hydro One's inability to achieve the Board ordered compensation reduction due to union contract obligations; higher Shared Services & Other costs, as a consequence of increased cost of goods sold[1] associated with external work and SAP sustainment costs; as well as a small increase in Sustaining programs. These increases in OM&A costs were offset by a $5 million decrease in Taxes Other Than Income Taxes (due to lower rights payments and a successful tax appeal) and $5 million lower Operations expenses largely due to higher than expected staff attrition and delays in new staff hires.

[1] The increased cost of goods sold in 2009 is offset by higher miscellaneous external revenues. The net difference between these two amounts has been placed into the "External Station Maintenance and E&CS Revenue" variance account.

Table 3 compares 2010 projected costs to the 2010 OM&A expenditures approved by the Board in their Decision on Hydro One Transmission's previous application in Proceeding EB-2008-0272.

Table 3
2010 Board Approved versus 2010 Projected OM&A Expenditures

OM&A Categories	**2010 Board Approved** ($ million)	**2010 Projected** ($ million)	**Variance** ($ million)
Sustaining	225.1	224.4	(0.7)
Development	13.1	19.0	5.9
Operations	58.9	62.1	3.2
Shared Services & Other Costs	55.8	58.6	2.8
Customer Care	1.5	1.1	(0.4)
Taxes other than Income Taxes	71.8	69.4	(2.4)
Total	**426.2**	**434.5**	**8.3**

Hydro One Transmission's actual 2010 OM&A costs are $8 million higher than the $426 million approved by the Board in Proceeding EB-2008-0272. This difference is primarily related to Hydro One's inability to achieve the Board ordered compensation reduction due to union contract obligations; initiation of smart zone Development work; and, an increase in Operations support costs driven by a technology change to the Network Management System. This is partially offset by lower Taxes Other Than Income Taxes.

TRANSMISSION ASSETS AND INVESTMENT STRUCTURE

1.0 INTRODUCTION

Sustaining programming for Operating, Maintenance and Administration (OM&A) and Capital is developed to meet Hydro One's strategic objectives and performance targets that are described in Exhibit A, Tab 4, Schedule 1, Section 3 - Summary of Transmission Business.

This exhibit provides a summary and additional information concerning the OM&A and Capital investment structure submitted with Exhibit C1, Tab 2, Schedule 3 and Exhibit D1, Tab 3, Schedule 2 respectively.

As well, Appendix A of this exhibit provides a detailed description of the transmission assets that are managed by Hydro One.

Asset-specific information on the decision making process for sustaining investments can be found in Exhibit D1, Tab 2, Schedule 1.

2.0 TYPES OF SUSTAINMENT WORK

Sustainment programming for OM&A and Capital involves decision making that determines the appropriate level of investment to meet Hydro One's objectives. While the specifics of the kinds of work differ amongst the assets involved, it is possible to identify broad categories of work that apply to Sustaining activities.

2.1 SUSTAINMENT – OM&A WORK

The following are the categories of Sustaining OM&A work that are typically defined and executed at Hydro One:

Planned Preventive and Corrective Maintenance: includes scheduled (time based) and condition based Preventive Maintenance (PM), as well as planned corrective maintenance. In addition, it can include targeted asset condition assessments.

Planned maintenance is conducted to meet Hydro One's obligations defined by the Transmission System Code to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments". Planned Maintenance for P&C is defined to meet the stringent requirements also defined by the Transmission System Code to conduct "routine verification [that] shall ensure with reasonable certainty that the protection systems respond correctly to fault conditions." Planned Maintenance ensures that Hydro One's assets are functioning properly by completing systematic inspection, detection, and correction of defects before failure or before they develop into major problems that will be more costly to correct later or become safety issues.

Mid-Life Overhaul/Refurbishment: is conducted to replace worn subcomponents of specific power system equipment and to increase its efficiency and reliability. The primary goal of this type of maintenance is to achieve the design life of the equipment in question and thereby defer capital expenditures. Major maintenance of this type must be both technically and economically feasible before being executed. Mid-life overhaul is primarily carried out on station assets such as transformers and breakers.

Unplanned Corrective Maintenance: includes unplanned corrective maintenance as well as response to emergency situations. This type of maintenance results from all unscheduled, non-programmed maintenance caused by unforeseen problems and/or equipment failure. Corrective maintenance is required to address the risk of harm and/or damage to any or all of employee safety, public safety, system reliability or environment. Unplanned corrective also includes work that was discovered during the course of planned maintenance activities where resolution should not be deferred until a future scheduled maintenance activity.

2.2 SUSTAINMENT – CAPITAL WORK

The following are the categories of Capital work that are typically defined and executed at Hydro One:

Planned Replacement: Hydro One mitigates system risk by replacing assets that have been identified to be at end of life (EOL). End of Life is defined by the likelihood of failure and where the failure of the asset would cause unacceptable negative consequences. Replacement is chosen for assets when there is no technically or economically feasible maintenance option such as increased planned maintenance, refurbishment of the asset, or a system reconfiguration option that may eliminate the need for the asset in question. Replacement can take the form of individual components, e.g., wood poles, insulators, or complete systems such as transformers with bus work and protections.

Emergency Equipment Spare Purchases: Hydro One maintains a pool of spare equipment for specific assets as part of the asset management strategy. Capital funding is used to purchase spare transformers and circuit breakers, to provide spares over a group of assets that minimizes capital investments while maintaining a sufficient reliability level. The determination of optimal level of spares for specific assets is determined through statistical methods based on the historical failure rate of the assets, the procurement time of the asset and the time to install the asset. The final number of spares purchased is adjusted by considering the actual condition of the assets to account for any expected change in the rate of failure.

Demand Driven Capital Replacement: In certain program areas Hydro One maintains capital funding in reserve to fund unforeseen equipment failures. Forecasts for the funding are set to historical spending levels unless trending or specific situations would indicate that a change is warranted.

3.0 SUSTAINING CAPITAL AND OM&A PROGRAMS

The assets under management are divided amongst three asset categories: Stations, Protection & Control (P&C), Telecom and Metering, and Lines. It should be noted that in Exhibit C1, Tab 2, Schedule 3 and Exhibit D1, Tab 3, Protection & Control and Telecom are presented as a subset of Stations, as the majority of these facilities are located within the transmission stations. The OM&A and Capital programs are linked by specific assets. The dominant linkages amongst the assets and their related Capital and OM&A programs are shown in the following tables.

Table 1

Stations Capital and OM&A Asset Linkages

<table>
<tr><th><u>Capital Category</u></th><th><u>OM&A Category</u></th><th><u>Assets</u></th></tr>
<tr><td>Station Environment</td><td>• Land Assessment and Remediation
• Environmental Management</td><td>• Station Properties as related to LAR
• Oil Containment Systems
• Transformer Gasket Systems</td></tr>
<tr><td>Circuit Breakers</td><td rowspan="4">Power Equipment Maintenance</td><td>• Oil Circuit Breakers
• SF6 Circuit Breakers
• Metalclad Breakers
• Vacuum Breakers</td></tr>
<tr><td>Station Re-investment</td><td>Can include all station equipment, with a focus on
• Gas Insulated Switchgear
• Air Blast Circuit Breakers
• Boilers and Pressure Vessels
• Metalclad Switchgear</td></tr>
<tr><td>Power Transformers</td><td>Transformers</td></tr>
<tr><td>Other Power Equipment</td><td>• Transmission Switches
• High Voltage Instrument Transformers
• Station Insulators
• Station Cables and Potheads
• Capacitor Banks
• Station Buses
• Station Surge Protection
• Station Structures</td></tr>
<tr><td>Ancillary Systems</td><td>Ancillary Systems Maintenance</td><td>• High Pressure Air Systems
• Batteries and Chargers
• Station Grounding Systems
• AC/DC Service Equipment
• Oil and Fuel Handling Systems</td></tr>
<tr><td>Transmission Site Facilities and Infrastructure</td><td>Site Infrastructure Maintenance</td><td>• Station Properties
• Station Buildings
• Fences
• Drainage and Geotechnical
• Fire and Security Systems
• Heating, Ventilation and Air Condition</td></tr>
</table>

Table 2

P&C, Telecom and Metering Capital and OM&A Asset Linkages

Capital Category	**OM&A Category**	**Asset**
Protection, Control and Metering	Protection, Control, Monitoring and Metering Equipment Maintenance	• Revenue Metering • Protection & Control and System Monitoring
NERC Cyber Security	Cyber Security	All NERC and NPCC regulated Critical Cyber Assets and vulnerabilities
Auxiliary Telecommunication Equipment	Telecommunications	• Power Line System • Microwave Radio Systems • Fibre Optic Cables • Metallic Cable • Site Entrance Protection Systems • Teleprotection Tone Equipment

Table 3

Lines Capital and OM&A Asset Linkages

Capital Category	**OM&A Category**	**Asset**
N/A	Vegetation Management	Rights-of-Way
Overhead Lines Refurbishment and Component Replacement	Overhead Lines Programs	• Phase Conductor • Wood Pole Structures • Line Steel Structures • Shieldwire and Hardware • Line Insulators and Hardware
Transmission Lines Re-investment		
Underground Lines Cables Refurbishment and Replacement	Underground Cable Programs	• Underground Cables and Potheads • Pumping Stations

The spending between capital and maintenance programs is linked to some degree for sustaining investment. Reductions in one specific area will impact other spending areas. If an area of investment was reduced over the planning period, it would compromise long-term costs, reliability and customer satisfaction among other business values. The following tables summarize some of the impacts of reducing specific capital and maintenance areas in Stations and Protection & Control, Telecom and Lines.

Table 4A - Capital

Capital and OM&A Spending Linkages

Investment Area	Spending Impacts of Reductions
Circuit Breaker – Capital	• Power Equipment – OM&A: Increase in corrective maintenance because of equipment failures and possible increase in refurbishment to maintain reliability. Potential increases in preventive maintenance to maintain reliability levels. • Environmental – OM&A: Potential increase in corrective maintenance because of equipment failures resulting in spilled oil. • Power Transformer – Capital: Breaker failures during fault clearing operations expose transformers to longer fault durations. This advances EOL of power transformers.
Station Reinvestment – Capital	• Power Equipment – OM&A: Increase in corrective maintenance because of equipment failures and possible increase in refurbishment to maintain reliability. Potential increases in preventive maintenance to maintain reliability levels. • Environmental – OM&A: Potential increase in corrective maintenance because of equipment failures spilling oil. • Power Transformer – Capital: Breaker failures during fault clearing operations expose transformers to longer fault durations. This advances EOL • Other Power Equipment and Ancillary – Capital: If this equipment is not replaced through integrated projects there will be long term pressures to replace EOL assets individually, as opposed to more efficient replacement through bundled investments
Power Transformer – Capital	• Power Equipment – OM&A: Increase in corrective maintenance on transformers and possible increase in refurbishment to maintain reliability levels. • Environmental – OM&A: Potential increase in corrective maintenance because of equipment failures spilling oil.
Other Power Equipment – Capital	• Power Equipment – OM&A: Increase in corrective maintenance because of equipment failures. Potential increases in preventive maintenance to maintain reliability levels.

Investment Area	Spending Impacts of Reductions
Ancillary – Capital	• Power Equipment – OM&A: Increase in corrective maintenance because of related equipment failures (especially high pressure air systems which supply air blast circuit breakers). Potential increases in preventive maintenance to maintain reliability levels. • Ancillary – OM&A: Increase in corrective maintenance because of equipment failures. Potential increases in preventive maintenance to maintain reliability levels. • Circuit Breaker – Capital: If air systems are not maintained moisture could have serious impacts on the reliability of the air blast circuit breakers, leading to potential failures.
Station Environment - Capital	• Environmental – OM&A: Increase in corrective maintenance because of clean-up and stop gap measures required with ineffective spill containment systems.
P &C, Telecom, Metering - Capital	• P&C – OM&A: Increase in corrective to maintain stability. Increase in re-verification to maintain reliability. • Telecom – OM&A: Increase in corrective to respond to failures and make repairs. • Power Equipment - OM&A: Increase in corrective as a result of miss operations causing equipment damage. • Power Transformer – Capital: Defective protection schemes can result in transformers being exposed to faults for a longer period during clearing operations. This advances EOL of power transformers.
Site Infrastructure & Security - Capital	• P &C, Telecom, Metering – Capital and OM&A: Potential increases in P&C corrective maintenance and required capital replacement because of site drainage issues or air conditioning system failures, leaking roofs. • Circuit Breakers and Transformers Capital and OM&A: Potential increases due to failures of fire protection systems.
Overhead Lines - Capital	• Lines – OM&A and Capital: Increase in corrective OM&A and Capital to manage an increase in defects and failures if EOL replacements are reduced. Increase in preventative maintenance for stop gap measures.
Underground Cables - Capital	• U/G Cables – OM&A and Capital: Increase in corrective OM&A and Capital to manage an increase in defects and failures if EOL replacements are reduced. Increase in preventative maintenance for stop gap measures and added diagnostics.

Table 4B – OM&A

Capital and OM&A Spending Linkages

Investment Area	Spending Impacts of Reductions
LAR – OM&A	• Environmental and Facilities: Increase cost to manage on site containment.
Environmental – OM&A	• Power Transformer – Capital: There is the potential for increased pressure to increase power transformer replacements if oil leaks are not repaired. • Environmental – OMA – corrective would increase with reduced oil leak reduction and containment pit maintenance.
Power Equipment – OM&A	• Power Equipment – OM&A: Increased corrective maintenance because of equipment problems and failures. • Power Transformer and Breakers – Capital: If mid-life refurbishments and preventative maintenance programs were cut, transformer performance and condition would degrade, resulting in increased pressures to replace EOL power transformers.
Ancillary – OM&A	• Power Equipment – OM&A: Increase in corrective maintenance because of related equipment failures (especially high pressure air systems which supply air blast circuit breakers). • Ancillary – OM&A: Increase in corrective maintenance because of equipment failures. • Circuit Breaker – Capital: If air systems are not maintained moisture could have serious impacts on the air blast circuit breakers. • Ancillary – Capital: Increase in replacement in grounding systems, station service and batteries and chargers are possible because of a lack of Ancillary OM&A.
P &C, Telecom, Metering – OM&A	• P &C, Telecom, Metering – Capital: Potential increases in P&C capital because of lack of maintenance contributing to failure of equipment. • Increased cost of outages affecting capital and OM&A programs due to correctives not addressed • Increased cost in demand corrective
Site Infrastructure – OM&A	• Site Infrastructure – OM&A: Increase in corrective maintenance because of fire protection systems and Heating, Ventilation and Air-Conditioning systems. • P &C, Telecom, Metering – Capital and OM&A: Potential increases in P&C because of site drainage issues or air conditioning system failures. • Circuit Breakers and Transformers Capital and OM&A: Potential increases due to failures of fire protection systems.

Investment Area	Spending Impacts of Reductions
Overhead Lines – OM&A	• Lines – OM&A and Capital: Increase in corrective OM&A and Capital to manage an increase in defects and failures.
Underground Cables – OM&A	• U/G Cables – OM&A and Capital: Increase in corrective OM&A and Capital to manage an increase in defects and failures.

4.0 ASSET DESCRIPTIONS

Appendix A - Asset Descriptions, Demographics and Performance, provides descriptions for major transmission assets that are managed by Hydro One Transmission and require Sustaining Investments.

Appendix A:
Hydro One Transmission Assets

Asset Descriptions
Asset Demographics
Asset Performance

Hydro One Transmission Assets

1.0 Introduction

This report provides descriptions, demographic data and performance data for major transmission assets that are affected by Hydro One Sustaining investments. This report is intended to provide context for the investment programs described in Exhibit C1, Tab 2, Schedule 2 - Sustaining Operating, Maintenance and Administration (OMA) and in Exhibit D1, Tab 3, Schedule 2 - Sustaining Capital.

This report describes assets that are in the following categories:

- Station – Power System Equipment
- Stations – Protection and Control
- Lines

2.0 Station – Power System Equipment Descriptions

This section provides descriptions of major power system assets that are found at Hydro One Stations excluding Protection and Control assets.

2.1 Circuit Breakers - General

A circuit breaker is a mechanical switching device that is capable of making, carrying and interrupting electrical current under normal and abnormal circuit conditions. Abnormal conditions occur during a short circuit such as a lightning strike or conductor contact to ground. During these conditions, very high electrical currents are generated that greatly exceed the normal operating levels. A circuit breaker is used to break the electrical circuit and interrupt the current to minimize the effect of the high currents on the rest of the system.

Transmission system buses are typically configured to provide either a breaker and a half or a breaker and one third arrangement, providing a degree of redundancy. Medium voltage breakers are typically configured in a radial feeder arrangement but a degree of redundancy is provided by the feeder tie switch normally used at DESN stations. Breakers may be constituted either as a 3-pole unit, with the operating mechanisms of all three phases contained in a single tank; or 3 single-pole units, with each pole contained in its own tank, and linked together to operate simultaneously. General Purpose circuit breakers are intended to operate infrequently. Definite purpose circuit breakers are designed to operate frequently, for applications such as capacitor and reactor switching.

Hydro One currently manages approximately 4450 in-service circuit breakers. These breakers are separated into different classes based on specifications, voltage and manufacturer. The insulating medium determines the type of circuit breaker e.g. oil, air, vacuum or sulphur hexafluoride (SF_6) gas. Circuit breaker technology has evolved over time with the use of these insulating media i.e.

oil was developed first, then high pressure air blast circuit breakers (ABCBs), and now vacuum and SF_6 Air blast technology replaced oil to cope with the higher power system voltages (the physical space and oil volume requirements at these higher voltages are enormous), but it also eliminated the environmental and fire hazards associated with oil. SF_6 was later introduced to replace air because it is a very stable, chemically inert gas whose insulating properties are 2-3 times greater than air making it ideal for use at high system voltages.

Circuit breakers are intended to operate infrequently; however, on the occurrence of an electrical fault, the breaker must operate reliably and very quickly to interrupt the fault without damage to itself and with a minimum disturbance to the remainder of the circuit and the electrical system. Typically, they are capable of interrupting currents in as short a time as 32 milliseconds.

Hydro One currently employs a variety of breaker technologies and ratings at non-GIS substations. The majority of the oil and air blast, (obsolete technology) circuit breakers are over 40 years of age with some approaching 60 years since their original manufacture.

While SF6 and Air Blast designs are applied across the complete medium and high voltage rating spectrum, oil circuit breakers are not applied beyond the 230kV level. Magnetic Air and Vacuum technologies are restricted to the medium voltage categories below 50kV and together with their medium voltage SF6 counterparts are applied, in outdoor air insulated stations (AIS) and in indoor metalclad switchgear arrangements. The majority of SF_6 breakers and essentially all oil breakers within the Hydro One system are of the dead tank type. Typically the dead tank design is the most cost effective since it can incorporate all necessary current transformers, thereby reducing space and installation requirements. Due to physical similarities, many oil circuit breakers that have reached the end of their service lives are being replaced with dead tank SF_6 breakers.

In dead tank design, the interrupter chamber is accommodated in a grounded metal housing. SF_6 gas serves as an insulator between the live contact assembly and the surrounding metal housing. High voltage terminals are connected to the interrupter chamber through outdoor bushings. Bushings normally incorporate bushing CTs thus avoiding the need for free standing HV current transformers. Dead tank circuit breakers employing both the old double-pressure technology and the newer, and simpler, single pressure technology have been applied on the Hydro One system. The dead tank design has been widely used at the medium voltage levels and at the lower transmission voltage applications (115 and 230 kV, but has also been developed for application at the highest voltage levels). Several have been successfully applied on the Hydro One 500 kV system.

In the live tank design, the interrupter chamber, which may be of the porcelain or composite material, is supported and insulated from ground, by vertical insulating support columns. Thus the chamber or tank is operated at system voltage. Voltage level determines the dimensions of the support and the tank insulators.

A very small portion of Hydro One HV SF_6 breakers and all HV air blast breakers are of the live tank type and are normally associated with separate, free standing, current transformers.

2.1.1 Oil Circuit Breakers

Oil Circuit Breakers (OCBs) are installed on the power system to interrupt load and fault currents and to de-energize power carrying assets to facilitate maintenance. An OCB consists of either one or three steel tanks filled with insulating oil in which pairs of operating contacts are immersed. These contacts are enclosed in an arc control “pot” which enables rapid extinction of the arc during an interruption.

A typical high voltage OCB used by Hydro One is shown in Figure 1.

Figure 1 - Three Tank Oil Circuit Breaker

Method of Arc Extinction

The method of arc extinction employed in OCBs is high-resistance interruption. The arc is controlled in such a way that its resistance is caused to increase rapidly, thus reducing the current until it falls to a value that is insufficient to maintain the gas ionization process.

Main Components

The main components of bulk OCBs are listed below, along with a short description of their use and purpose:

Control Cabinet and Operating Mechanism

The cabinet contains control relays, wiring, heaters, current transformer terminals, and the breaker-operating mechanism.

Tank

The tank contains the oil, the interrupter units, support mechanisms and operating rods and linkages to ensure simultaneous operation of each interrupting unit. Current transformers for protective relaying and metering purposes are also installed inside the tank where the incoming high voltage connections are located.

Exterior of the Tank

Oil-filled bushings are mounted on the tank for electrical clearance and the connection of the breaker into the power system.

2.1.2 SF6 Circuit Breakers

The first SF_6 circuit breaker was developed in the late 1960s and was a double-pressure design (low pressure tank and high pressure reservoir), based on the air blast technology. The double pressure design is very complex both electrically and mechanically and was quickly rendered obsolete by the single pressure design developed in the mid 1970s. The simpler, single pressure SF_6 insulated circuit breaker, despite some early design reliability issues, has now become the technology of choice for transmission class circuit breakers. No compressor or other complex auxiliary equipment is required, since the gas for arc interruption is compressed in a puffer action by a piston during the opening operation. Recent improvements in the single pressure design, by the use of self blast or other related techniques to assist the interrupting process, has resulted in still simpler and more reliable breakers using spring charged or hydraulic-spring operating mechanisms.

A typical HV SF_6 circuit breaker used by Hydro One is shown in Figure 2.

Figure 2: Dead Tank SF_6 Circuit Breaker

Hydro One introduced SF_6 equipment to the system at a very early stage in its evolution during the 1970s. As a result of this, they did suffer from significantly raised failure rate due to prototype problems. In addition, the degradation in performance was accelerated by the more onerous operating and special purpose switching conditions encountered on the Hydro One system.

A large proportion (about 30%) of the SF6 breaker population is applied for the most onerous, special purpose duties, such as reactor and capacitor bank switching, some involving several hundred operations per year thus accelerating the mechanical and electrical wear out of the breaker. The complex control and operating mechanisms installed in almost all of these early vintage breakers resulted in increased operating problems and significant maintenance and refurbishment expenditures. Most of these very poor performing breakers have reached or surpassed their mechanical design life of 2000 switching operations.

Heaters are required on many of these breakers to prevent liquefaction of the SF6 gas at the low temperatures prevailing in Ontario. Heaters and control equipment, contactors, thermostats, and wiring degrade at an accelerated rate under these extreme conditions.

Gas seals leak at an increased level at low temperature putting increased pressure associated apparatus. Generally, earlier models have more problems than later ones, since modern equipment has improved seal and valve designs.

2.1.3 Air Blast Circuit Breakers (ABCBs)

High voltage (115kV, 230kV and 500kV) ABCBs are typically applied in “breaker and a half” and “breaker and a third” schemes which provide improved reliability by redundancy. Low voltage (less than 50kV) ABCBs are connected radically to supply load to individual feeders. A typical HV ABCB used by Hydro One is shown in Figure 3 below.

Figure 3: 230 kV Air Blast Circuit Breaker

ABCBs are complicated in design and incorporate a large number of moving parts, valves and seals. They also require a high-pressure compressed air (HPA) supply. Centralized HPA systems are installed at all locations that have a population of ABCBs. The HPA systems are usually comprised of multi-stage compressors, chemical or heated dryers, numerous air storage receivers, extensive piping and valving arrangements, and controls. The design, condition and successful operation of the central air systems have a direct bearing on the capability of the ABCB to properly perform its designed function. Excessive moisture in the air could lead to explosive failure of circuit breakers. Conversely if ABCBs experience excessive leakage it will result in excessive run times for compressors and dryers and increased maintenance and refurbishment costs related to the air system

The utility industry has identified degradation of gaskets, seals, and valves as the critical long-term issues related to EOL of ABCBs. Experience has shown that gasket and seal deterioration is time-related with major performance problems being experienced when gaskets and seals are 20-25 years old. To deal with these in the past Hydro One has undertaken a major rebuild of each ABCB after approximately 20-25 years of service. The last rebuild program was completed in 1995. OEM facilities and resources associated with the rebuild program are no longer available and major rebuilds are no longer feasible.

2.1.4 Gas Insulated Switchgear (GIS)

Gas insulated switchgear (GIS) is an assembly of switchgear in which all of the major components, except for the entrance bushings, are housed within a grounded metal enclosure containing pressurized sulphur hexafluoride (SF_6) gas. The GIS is compartmentalized in such a manner as to readily facilitate maintenance of individual components with minimum disruption to adjacent components and also to minimize gas losses in the event of an uncontrolled rupture of an enclosure. Many compartments are fitted with pressure relief devices which are designed to relieve excess pressure in the event of an internal fault and so prevent enclosure rupture. GIS is very compact compared to AIS and is applied at all the voltage levels, LV, HV and EHV on the Hydro One system. Gas insulated switchgear is an attractive alternative to an outdoor air insulated substation (AIS), particularly where space constraints and protection from harsh environmental conditions are a consideration.

All are indoor installations. Some are in heated buildings, while others are in unheated buildings. Several stations have extensive outdoor runs of bus between the GIS and associated overhead line terminations and transformers. As shown in Figure 4 and 5, the GIS incorporate some or all of the following components:

- Circuit breakers
- Switches - disconnect and ground switches
- Bus

Other equipment including: SF_6/air entrance bushings; SF_6/cable terminations, instrument transformers, current and voltage transformers, surge arresters and protection, control, and monitoring equipment

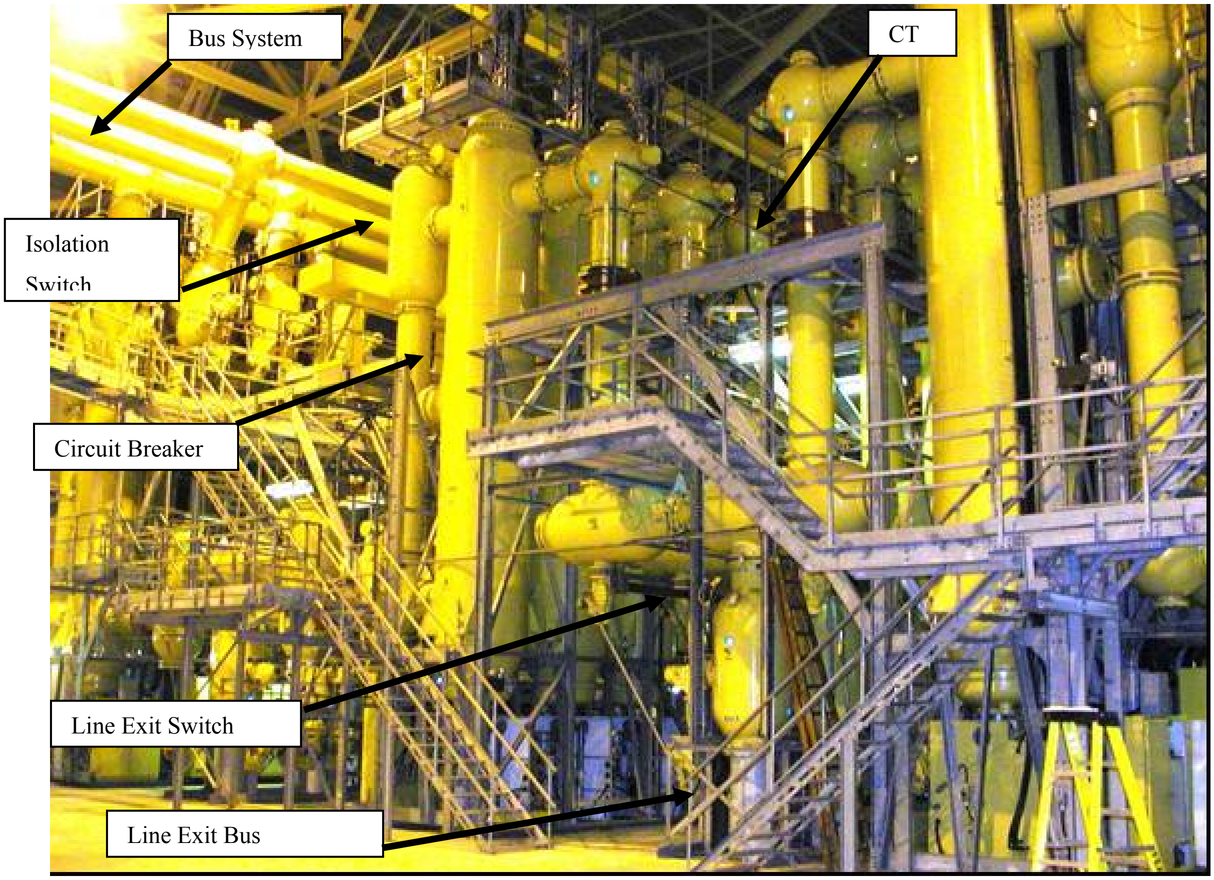

Figure 4: 500 kV GIS Indoor Equipment

Figure 5: 500 kV GIS Outdoor Exit Bus Equipment

Metal enclosed, concentric, SF_6 insulated buses are used to interconnect other live GIS components such as circuit breakers, disconnect switches and interfaces with overhead lines, cables and transformers. Within the bus, aluminum conductors are supported on epoxy resin insulators. About 30% of the failures which have occurred since the late 1970s have been on these epoxy resin insulators. The current failure rate is considerably lower and Hydro One has developed diagnostics and monitoring procedures to detect potential failures.

2.1.5 Metalclad Switchgear

Metalclad switchgear is an assembly of switchgear in which all of the major components are housed within a grounded metal enclosure. Construction for this type of equipment utilizes insulated bus and compartmentalization. The switchgear is compartmentalized in such a manner that all major power components are completely segregated from each other by a grounded metallic enclosure. Metalclad switchgear is an attractive alternative to an outdoor air insulated substation (AIS), particularly where space constraints and protection from harsh environmental conditions are a consideration.

All Hydro One metalclads are indoor installations. Some are in heated buildings, while others are in unheated buildings. The switchgear incorporates some or all of the following components:

- Circuit breakers
- Switches
- Bus
- Other equipment including: entrance bushings; cable terminations, instrument transformers, current and voltage transformers, surge arresters and protection, control, and monitoring equipment

The majority of Hydro One's voltage metalclad switchgear installations consist typically of an indoor line-up of 10 to 14 cells as illustrated in Figure 6.

Figure 6: Typical Hydro One Metalclad Switchgear

Figure 7 shows a typical circuit breaker withdrawn from the Metalclad Switchgear.

Figure 7: Circuit Breaker Withdrawn from Breaker Compartment

Figure 8 shows a typical control cabinet that is located within the Metalclad Switchgear.

Figure 8: Control Compartment

There are a variety of circumstances that result in internal arcs in metalclad switchgear. Often times this failure occurs when the breaker fails during routine switching or when clearing a through fault. A dangerous situation also exists when a breaker fails to properly open prior to racking-in or racking-out. Other causes of internal failure are due to partial discharge activity that weakens the insulation over time. Overvoltage surges on equipment with weakened insulation can result in internal failure. Operational mishaps can occur to cause internal faults such as mis-operation, or tools, grounds or other equipment being left in a cubicle during maintenance checks.

Although the probability of an arcing fault inside MV metal-clad switchgear is low, the cost in terms of personnel safety and equipment damage is high when an arcing fault occurs. Since the early 1980's some Canadian utilities including Hydro One have purchased arc resistant medium voltage switchgear. Hydro One still retains a significant population of older switchgear on the system which was retrofitted with minimum arc resistance provision but does not meet current standards for arc resistance. The majority of the circuit breakers in these switchgears are either obsolete air magnetic or SF6 designs. All modern switchgear incorporates vacuum circuit breakers for economic reasons and because of environmental concerns with SF6.

Arc resistant switchgear is characterized by some special design features necessary to achieve the required ratings. The switchgear enclosure construction must be designed to contain the internal arc pressure and direct it to the pressure relief flaps or exhaust chambers designed to safely vent the arc products. Movable vent flaps are designed to open due to the arc fault pressure, increasing the volume containing the arc products. Any ventilation designs with flaps that are open under normal operating conditions must close when an arc fault occurs

Racking and operation of all equipment such as circuit breakers, switches and instrument transformers must be through closed doors.

The integrity of the low voltage control and protective device circuitry is critical. Instrument compartments, which contain the protective relays, meters, devices, and wiring, should be separate reinforced modules. The interior surfaces of the instrument compartment are considered as part of the arc resistant enclosure boundary and must satisfy the same criteria as the switchgear enclosure during type testing. This protects personnel who may be working in or near the compartment as well as the P&C devices themselves, and control wiring which may otherwise be destroyed as a result of the arc fault. This is extremely important as the protective scheme is being relied on to limit the duration of the arc fault.

Sufficient clearance must be provided above the switchgear to allow the arc products to be dispersed properly and not to be reflected back into the area that could be occupied by personnel. Additionally sufficient clearance from the pressure relief flaps should be provided for any control cable trays, medium voltage insulated cables, buses or other electrical equipment located above the switchgear. Where appropriate clearances are not possible due to the design of the enclosure/building, an exhaust plenum can be provided to safely vent the gases externally to an area that is not accessible to personnel. The plenum design must be tested to verify satisfactory performance under internal arc fault conditions.

Studies in the past indicate that certain existing indoor metalclads of simple design (i.e. few compartments per cell) can be retrofitted with limited arc resistant functionality. This has been implemented in all of the pre-1985 metalclads which comprise about 50% of the Hydro One metalclad population. However this limited arc resistance functionality does not generally comply with Hydro One current Safety and Arc Flash requirements. In addition at least 10 of these installations require the cell door to be opened and the circuit breaker to be manually levered into place, which represents a high risk for personnel safety.

2.2 Transmission - Power Transformers

Transformers are static devices whose primary purpose is to either step-up or step-down voltage. Transformers change AC electric energy at one-voltage level to AC electric energy at another level via induction of a magnetic field. A transformer consists of two or more coils of wire wrapped around a common ferromagnetic core. One of the transformer windings is connected to the source of the AC electric power called the primary or input winding, and the second winding connected to the load is called the secondary or output winding. The main connection between the windings is the common magnetic flux present within the transformer's core.

2.2.1 Power Transformers

The purpose of a power transformer is to convert large amounts of electrical power from one voltage level to another. These devices vary in size from that of a small car to the size of a small house. There are two general classifications of power transformers: transmission transformers and distribution transformers. Transmission transformers connect transmission lines of various voltages to one another. Transmission power transformers are almost always fitted with the under load tap changer (ULTC) mechanism. A picture of a typical Hydro One's transmission station power transformer is shown in Figure 9.

Figure 9: Typical Transmission Station Power Transformer

Transformers are made up of the following primary components. Some components are optional, as indicated below, depending on the transformer application:

- Primary and secondary windings each installed on a laminated iron core
- Some also have tertiary windings
- Internal insulating mediums
- Main tank
- Bushings
- Cooling system, including radiators, fans and pumps (Optional)
- Off circuit tap changer De-energized tap changer (Optional)
- ULTC LTC (Optional)
- Current and potential transformers
- Mechanism cabinets.

Primary and Secondary Windings

The primary and secondary windings of a transformer are each installed on a laminated iron core and serve as the coils that react with the magnetic flux of the transformer core. When the magnetic circuit takes the form of single ring encircled by two or more groups of primary and secondary windings distributed around the periphery of ring, the transformer is termed a core type transformer. Core type transformers represent close to 100% of the power transformers built today and are widely applied because the design is technically reliable and it is cost effective. Figure 10 shows the construction of a single-phase core type transformer.

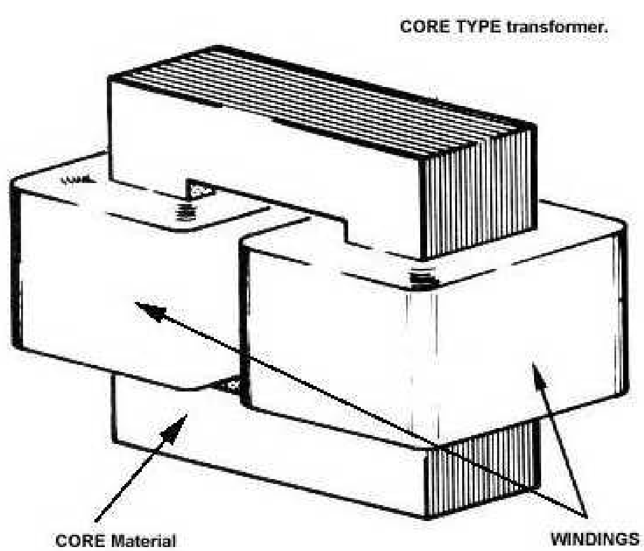

Figure 10: Core Type Transformer

When the primary and secondary windings take the form of a common ring that is encircled by two or more rings of magnetic material distributed around its periphery, the transformer is termed a shell type transformer. Figure 11 shows the construction of a shell type transformer.

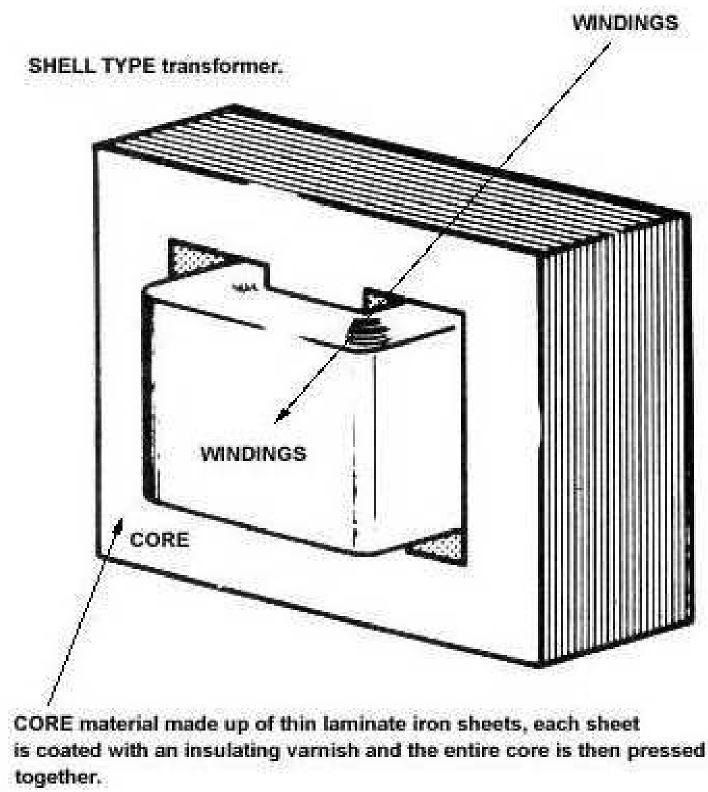

Figure 11: Shell Type Transformer

Shell type transformers are an older, more complex, transformer design that are more costly to build, but normally exhibit a superior short circuit withstand capability. Westinghouse transformers built prior to 1965 are of this design. The winding materials are made of both copper and aluminum, available in sheet (foil) and rectangular conductor configurations. For transposed cable applications only copper is used.

Internal Insulating Mediums

The internal insulating mediums serve as the necessary electric insulation and in the case of mineral oil as a coolant. Low cost, high dielectric strength, excellent heat-transfer characteristics, and ability to recover after dielectric overstress make mineral oil the most widely used transformer insulating material. The oil is reinforced with solid insulation in various ways. The major insulation usually includes barriers of wood-based paperboard (pressboard), the barriers usually alternating with oil spaces. Because the dielectric strength of oil is approximately half that of the pressboard, the dielectric stress in the oil is higher than that in the pressboard, and the design structure is usually limited by the stress in the oil. The insulation on the conductors of the winding may be enamel or wrapped insulating paper tape which is either cellulose or nylon based. The use of insulation directly on the conductor actually inhibits the formation of potentially harmful electrical breakdown streamers in the oil, thereby increasing the strength of the structure. Heavy paper wrapping is also usually used on the leads which connect the windings to the external terminals of the transformer.

Main Tank

The main tank is used to hold the active components of the transformer in an oil volume that maintains a sealed environment through the normal variations of temperature and pressure. Typically the main tank is designed to withstand a full vacuum for initial and subsequent oil fillings and is able to sustain a positive pressure. The main tank also supports the internal and external components of the transformer. Main tank designs can be classified into 2 types those being conservator and sealed types.

Hydro One typically uses conservator types which have an externally mounted tank that is designed to hold up to 12% of the main tank's volume. As the transformer oil expands and contracts due to system loading and ambient temperature changes, the corresponding oil volume change must be accommodated. This tank is used to provide a holding mechanism for the expansion and contraction of the main tank's oil over these temperature variations. This design reduces oxygen and moisture contamination since normally only a small portion of oil is exchanged between the main tank and the conservator and a minimum volume of the oil is exposed to the air. However, eventually oil in the conservator is exchanged with oil in the main tank and oxygen and other contaminates gain access to the insulation.

Bushings

Bushings are used to facilitate the ingress of the electric power circuits in an insulated, sealed (oil-tight and weather-tight) manner. A bushing is typically composed of an outer porcelain body mounted on metallic flange. The phase leads are either independent paper insulated, or are an integral part of the bushing. At the higher voltage levels, additional insulation is incorporated in the form of mineral oil and wound paper stress cone installed within the porcelain body.

Power transformers bushings can be roughly divided into "bulk" and "condenser" types and are used on the primary and secondary winding connections including the neutral points.

Cooling System (Radiators, Fans, and Pumps)

Cooling systems provide a means for the removal of internal heat generated through the transformer losses. The system is necessary to prevent the build up of excessive internal temperatures that would shorten the life of the insulation systems. Transformer cooling system ratings are typically expressed as:

- Self-cooled (radiators) with designation as ONAN (oil natural, air natural).
- Forced cooling first stage (fans) with designation as ONAF (oil natural, air forced).
- Forced cooling second stage (fans and pumps) with designation as OFAF (oil forced, air forced).
- Forced cooling first or second stage (fans and pumps) with designation as ODAF (oil directed, air forced).

The utilization of a number of cooling stages allows for an increase in load carrying capability. Loss of any stage or cooling element may result in a forced de-rating of the transformer.

Off Circuit Tap Changer (OCTC)

An OCTC is a device by which the power transformer turns ratio can be altered over small range to effect changes in output voltage as required. The change in ratio is typically accomplished in the high voltage winding by dividing the physical winding into two halves in combination with the use of several selectable winding taps. An OCTC application typically allows for an adjustment of 5% above nominal and 5% below nominal voltage in 2½ % steps. An OCTC must only be operated with the transformer off potential.

Underload Tap Changer (ULTC)

ULTCs allow for automatic voltage changes while adjusting to varying load conditions on line. An ULTC is of particular importance to those situations where frequent voltage regulation is required because of the characteristic of the load. ULTCs are complex in their design. As a control mechanism, they consist of moving mechanical parts, a drive motor, linkages and voltage regulation sensing equipment. The ULTC incorporates tapped connections to the main windings that can be selected automatically, through a series of main and arcing contacts, to adjust the secondary voltage of the transformer without interrupting the load.

Current Transformers

Current transformers (CTs) sample the current in a line and reduce it to a safe and measurable level. CTs consist of a secondary winding wrapped around a ferromagnetic ring (transformer bushing’s primarily lead), with the single primary line running through the centre of the ring. The ferromagnetic ring holds and concentrates a small sample of the flux from the primarily line. That flux then induces a proportional voltage and current in the secondary winding.

Mechanism Cabinets

The mechanism cabinet is an externally mounted box that supports voltage and current control relay, secondary control circuits, and in some cases the tap changer motor and position indicators.

2.2.2 Autotransformers

An autotransformer is a special case of power transformers, which are used primarily to transform voltages and currents between transmission system voltage levels (between 500 kV and 230 kV and between 230 kV and 115 kV in Hydro One's system). In the case of an autotransformer, there is no electrical isolation between the primary and secondary windings, as part of the winding is common and shared by the primary and secondary. This is a cost-effective solution in applications where the primary to secondary voltage ratios are less than about 2:1 and where the common connection is acceptable. Autotransformers can be fitted with the ULTC mechanism as well.

Because there is no electrical isolation between the primary and secondary windings in an autotransformer, no phase shift occurs between primary and secondary voltages. Most conventional two winding three phase transformers are built with a 30-degree phase shift inherent in the design. Therefore the application of autotransformers has to be carefully planned to ensure that the appropriate phase relationship exists in the system. In the Hydro One system autotransformers are used with primary voltages at 500 kV, 230 kV and 115 kV. However, those with a primary voltage of 115 kV are rarely needed and are only used where special phasing is required.

2.2.3 Phase Shifting Transformers

In an alternating current system, the voltage varies from maximum to minimum 60 times per second, or 60 Hertz. In two systems, both operating at 60 Hertz, there can be a shift between when the reference phase of one system peaks and the other system peaks. This would cause an electrical disturbance if both systems were interconnected. Real power flow in transmission systems is controlled through control of phase differences, therefore phase shifting transformers are employed in selected locations to optimize power flows in the system. Phase shifting transformers are very complex to design and manufacturer and often require a two-tank design.

2.2.4 Shunt Reactors

While strictly speaking, shunt reactors are not transformers, they are similar in construction and considered by Hydro One in the same asset class. A shunt reactor is basically a single winding wound on an iron core and its construction, maintenance and testing is similar to a power transformer.

A transmission line has two main electrical properties characteristic of its design, resistance and reactance. Reactance can be either inductive or capacitive, one cancelling out the effect of the other. Both resistance and reactance contribute to transmission line losses, while resistance is fixed and cannot be changed, the inductive reactance can be cancelled by capacitive reactance or increased by adding additional inductive reactance.

The primary purpose of shunt reactors is to introduce reactance into a circuit. Shunt reactors are normally used to absorb reactive power for voltage control. Series reactors are devices normally used to increase the effective reactance on a circuit to limit fault current.

2.2.5 Regulator Transformers

Regulator transformers are transformers whose sole purpose is to provide voltage regulation through use of an internal tap changer. The nominal incoming and outgoing voltages are the same but the outgoing voltage can be varied slightly in 2.5% increment to satisfy the voltage requirements of connected customers.

2.2.6 Grounding Transformers

Grounding transformers are used to provide a neutral point for grounding an electrical system.

Electrical distribution systems can be configured as a grounded or ungrounded system. A grounded system has an electrical connection between source and the earth, whereas an ungrounded system has no intentional connection. Sometimes it is necessary to create a ground on an ungrounded system for safety or to aid in protective relaying applications. Smaller transformers similar in construction to power transformers are used in this application.

2.2.7 Station Service Transformers

The operation of the transmission station requires power for various services such as lighting, operation of fans, relay room heating and ventilation, power for battery chargers, etc. The most reliable source of such power is directly from the transmission or distribution lines. Small power transformers are used to provide this power supply.

2.3 HV/LV Switches

Disconnect switches are used to visually and electrically isolate equipment or line sections of the transmission system for purposes of maintenance, safety, and other operating requirements. Disconnect switches generally have no assigned or tested current interruption capabilities. However it is common practice within Hydro One as in other North American utilities to use them to interrupt small bus currents of a few amperes and transformer magnetizing currents of limited magnitude. Also included in this asset class are load interrupter switches which have limited load and fault interrupting capability. The interrupter mechanism normally contains a gas/vacuum, as the insulating medium and these switches also must be capable of providing visual confirmation of the open/close position. The switches currently in use on the Hydro One transmission system have been purchased from more than 10 different manufacturers over the past 60 years.

In general switches consist of a mechanically movable copper or aluminums conductor /blade, supported on insulators and mounted on a metal base. Rotation of one or more of the insulator stacks causes the current path to make or break the circuit, as required as shown in Figure 12. The operating or control mechanism may be a simple hook stick, manually gang operated, or motor operated. The latter is primarily used on transformer and line circuits, where protective relays may be used to operate the switch automatically as shown in Figure 13. Disconnect switches are relatively simple in design compared to circuit breakers because they are not required to interrupt large currents in most applications.

Kearney (type DHB) 138kV 1200A Disconnect Switch

Figure 12: Center Rotating Disconnect Switch

ABB (type TTR-6) Motor Operated Disconnect

Figure 13: Motor Operating Mechanism for a Switch

Disconnect switches may be mounted vertically, horizontally or inverted and various switch designs may be deployed depending on the station arrangement of facilities. These are described according to their operation or blade motion as shown in Table 1.

Vertical Break	Blade contact rises out of the jaw contact-three insulator stacks are usually used
Side Break	Blade contact parts to the side
Double Break, Centre Rotating	Contacts at each end of the blade part to opposite sides due to the rotation of the centre of the centre of three insulator stacks
Centre Break, Both Ends Rotating	Both jaw and tongue contacts move to the one side by rotation of both insulator stacks.

Table 1: Switch Operation Description

A load interrupter switch typically comprises of a motor operated, three phase, load carrying and interrupting device having a limited fault interrupting capability, mounted on support insulators and metal support structure. The interrupter may be either air or vacuum, or SF6 which is the dominant technology on the Hydro One system. It may, or may not, incorporate disconnect blades for isolating purposes. Typical load carrying and breaking capabilities are in the 600A to 2000A range and interrupter switches have been applied in the MV, HV and EHV rating categories. Interrupters on the older designs were typically sealed for life and replaced rather than repaired upon failure. In some cases the OEM is no longer supplying or supporting the older design, thus driving the EOL decision process for certain applications. The more recent designs are very similar in design and operation to live tank SF6 circuit breakers. There are almost 300 load interrupter switches on the Hydro One system. Depending on the operating requirements, some switches are manually operated and others motor operated.

2.4 High Voltage Instrument Transformers (HVITs)

HVITs consist of voltage and current transformers that are independent, freestanding devices that are used in Hydro One' transmission stations at voltages of 115 kV and above.

The application of control, protection (relaying) and metering functions to HV systems requires the use of sensitive measuring devices, which are typically incapable of withstanding the high currents and high voltages present on the Hydro One' primary system. For this reason, the primary voltages and currents in typical HV systems must be accurately transformed to low values that are acceptable to the measuring devices. In HV systems special transformers called instrument transformers carry out this function.

There are two basic types of instrument transformers: voltage transformers (VTs) and current transformers (CTs).

VTs are devices for measurement of bus and line voltages that, on the primary side, are connected between the phase and neutral conductors of the HV system. The ratio of the primary to the secondary winding is typically chosen to provide a secondary voltage of 120 volts when the primary system voltage is at its nominal value. This secondary voltage is used for control, protection and metering devices and varies directly in proportion to the primary system voltage.

CTs are devices for measurement of line currents that are connected on the primary side in series with the phase conductors of the HV system. The ratio of the primary to the secondary winding is typically chosen to provide a secondary current of 5 Amps when the primary system current is at its nominal value. This secondary current is used for control, protection and metering devices and varies directly in proportion to the current in the primary system.

VTs and CTs in HV systems are usually oil insulated and enclosed in a high strength sealed porcelain insulator to withstand the applied voltage stresses. Presently, other types of current transformers are being supplied that use SF_6 as the insulating medium instead of oil.

There are two different types of voltage transformers: inductive and capacitive as described below.

An inductive VT is wound in the similarly to a conventional power transformer: it uses inductive coupling to reduce the primary (high) voltage to a lower analogue voltage. Inductive VTs can be used at any voltage level, but they are only cost effective at lower voltages, typically below 115 kV. In the Hydro One' system, inductive VTs are used primarily up to 44 kV.

The cost of inductive VTs increases significantly with increasing voltage, such that at voltages ≥115 kV, almost all VTs are of the capacitive type. This is mainly due to problems associated with winding inductive VTs at higher voltages and the increased difficulty in maintaining the insulation between the windings.

Capacitive voltage transformers use a capacitive voltage divider (connected phase to ground - one per phase) to obtain a lower voltage supply across the last capacitor in the stack. This voltage level typically ranges between 5 and 24 kV. A small, and accurate, induction transformer is used in the base of each single phase CVT to obtain an analogue voltage, typically 120 V, for use in measuring circuit voltage.

CVTs use wrapped paper to form small capacitors, which are then stacked to form the capacitive voltage divider. Insulation of the CVT (around the capacitors and the inductive transformer) is maintained by oil immersion.

Figure 14 shows a typical capacitive voltage transformer.

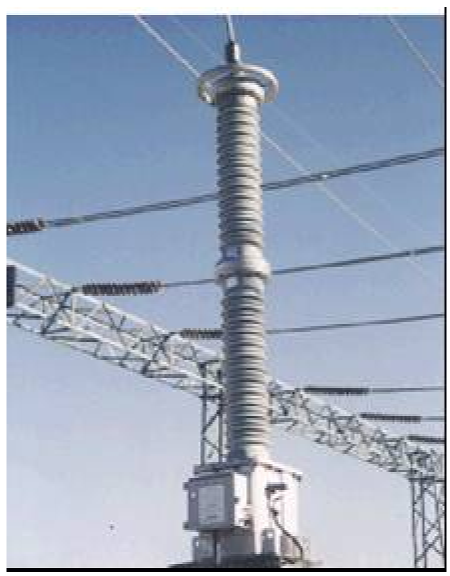

Figure 14: Capacitive Voltage Transformer

Together with the primary measuring function CVTs can also be used to moderate transient recovery voltages as may occur in the interruption of short line faults by circuit breakers.

Current transformers are wound inductive type transformers that are used to obtain an accurate low current analogue of HV currents. Rated CT secondary currents are either 5 A or 1 A. In North America the 5 A secondary rating is typically used. Current ratings are defined by Standards; in Canada the applicable Standard is CSA C13. CTs typically use oil as the insulating medium. However, Hydro One has a small number of SF_6 insulated CTs.

Instrument transformers must produce current and voltage waveforms reliably for use in control, relaying and metering circuits. The acceptable limits of accuracy are outlined in CSA C13. The following outlines the acceptable accuracy for current and voltage transformer applications.

For relay systems, the VTs must be accurate to 1% or 3%, depending on the accuracy class required (1P or 3P), over their applicable rated output range. There are 5 standard output ranges or burdens that are commonly specified, namely: W – 12.5 VA, X – 25 VA, Y – 75 VA, Z – 200 VA and ZZ – 400 VA. For metering systems, the VTs must be accurate to 0.3% over their applicable rated output. Similar standard output ranges or burdens as for relay applications apply. For some applications where harmonic waveform capture is required, special VT accuracy limits are required. Such special limits are separately covered in the Standards.

For relay systems, the CTs providing input current to relays must be capable of a nominal accuracy under rated conditions; but must be capable of producing 20 times rated output current, at an acceptable accuracy, under fault conditions. In North America, CTs used for relay systems typically must have a 10% accuracy at an output of 20 times nominal CT current, or 100 A for a 5 A rated CT. The CT must also be capable of a stated voltage output at the 20 times nominal secondary current.

For metering systems CTs must be capable of much higher accuracy than for protection applications; but they do not need to be capable of accurate output at the extreme currents encountered during a fault. For revenue accuracy circuits in Canada, the accuracy of a CT output must be 0.3% at rated current and the CTs must be certified by Measurement Canada. The second portion of the specification of a metering accuracy CT is the rated burden into which the CT must supply its rated current. Standard burdens in North America range between 1 and 3 ohms.

2.5 Station Insulators

Insulators are used in transmission stations for termination of conductors at structures and to support busses or equipment e.g. disconnect switches, circuit breakers, instrument transformers, etc.

Station insulators are subject to both electrical and mechanical stresses at the installation point. The electrical stresses are caused by the high voltage between live parts during normal and abnormal conditions. Abnormal conditions may include lightning strikes and operation in contaminated conditions. Sub-optimal insulator design or deteriorated conditions may result in loss of electrical withstand capability of the insulation leading to flashovers. Mechanical stresses include compression, torsion, tension and cantilever forces.

Corrosion of metal fittings, damage due to vandalism, and cement growth are some of the factors that adversely affect the mechanical integrity of the insulator. Extreme environmental conditions, such as harsh winter weather and industrial pollution, also reduce the mechanical and electrical strength of insulators. Insulator units with resistive glazed (RG) porcelain posts or having a silicone coating are often used to improve the withstand capabilities under these specific conditions.

The most common materials used in insulators are porcelain, glass and polymeric. The vast majority (over 99% -) of the station insulators in the Hydro One system are porcelain type insulators. Glass is used mostly for insulator strain and idler discs or polymeric type insulators are used mostly at lower voltages.

The types of insulators used in transmission stations are:

- Rigid support insulators mostly used for rigid bus support.
- Disc types for strain bus connections and for idler strings associated with strain buses

Rigid Insulators

Rigid insulators consist mostly of the "newer" station post type as shown in Figure 15 or the "older" cap and pin type as shown in Figure 16. These insulators isolate live apparatus from station structures and provide support for electrical conductors and equipment. They are also an integral component of disconnect switches, and capacitor banks etc., and these are also discussed as part of each asset class. Demographic data includes all insulators, irrespective of application.

Figure 15: Station Porcelain Post Insulator

Figure 16: Station Cap and Pin Insulators

Cap and Pin

The cap and pin insulator forms the majority of the station insulator population. Single units are applied at the low voltage levels below 50kV and cap and pin insulators are capable of modular stacking for use at 115kV and 230kV. Cap and pin insulators were manufactured from the early 1900's to the 1980's but this design of insulator is no longer available.

Cap and Pin insulator failure modes include radial cracking, circumferential cracking (also called doughnut cracking), head cracks, and punctures. Radial and circumferential cracks occur in the shed and although very fine, they are usually visible upon close inspection. Radial cracks can extend up into the insulator head. Head cracks and punctures are often hidden beneath the cap, and therefore are not amenable to detection by inspection. In addition, a large percentage of cap and pin insulators manufactured between 1965 and 1980 are experiencing premature end of life due to a condition called "cement growth", which causes the cement that holds the metal cap to the porcelain skirt to expand when moisture penetrates the cement, thereby separating, or breaking the insulator. Over 17% of the cap & pin insulator population fit into this profile. Failures of cap and pin insulators are of particular concern where they support under-hung buses or disconnect switches since personnel safety and damage to adjacent equipment is a major risk.

Station Post

These are one-piece or multi-piece porcelain or polymeric insulators with relatively small but numerous rainsheds and fitted with metal caps and base at the ends. The end caps and bases have tapped mounting holes to facilitate various mounting configurations. The number of insulators used in a stack depends on circuit voltages and design standards. These insulators are available with a variety of voltage ratings and cantilever strengths.

The post type insulator is used as a replacement for aging or defective cap and pin insulators. All new insulators purchased are of the post type. Single post insulators are used from 7.5kV to 115kV and stacked together for use at 230kV and 500kV. Polymeric post insulators are typically only applied at the low voltage level.

Post type insulators are constructed in a variety of ways as described below:

- **Multi-cone** – these insulators were developed as an alternative to cap and pin and station post type insulators. The multi-cone post insulator is an assembly of porcelain cones stacked together to form the desired insulator length and loading characteristics. The porcelain cones are held together with a cement compound. Multi-cone insulators are used at 230kV with BIL ratings of 900kV and 1050kV and 500kV having BIL ratings of 1550kV and 1800kV. One of the problems associated with this type of insulator construction is the effect of cement expansion on the porcelain due to temperature cycling, including freezing and thawing of the insulator. This expansion is caused by moisture being absorbed in the cement during its many years of life. The expansion causes longitudinal cracks to appear and weaken the insulator electrically. The insulator will weaken mechanically as more cracks develop. These insulators are no longer available.

- **Hollow Core** post insulators were developed to improve the firing and curing process during manufacture. Hollow core insulators allow for a more even heating of the porcelain due to its thinner walls. Fusing a porcelain or rubber plug into the hollow post during firing prevents breathing and ensures a clean, dry interior. The sealing process on some of the insulators was substandard and allowed moisture ingress, which caused a reduction in its dielectric properties and ultimately electrical failure. These insulators are usually installed at the low voltage levels (below 50kV) and were supplied as part of the disconnect switch by some manufacturers. Only a few such hollow core insulators exist on Hydro One disconnect switches. It is not possible to visually distinguish hollow core from solid core insulators. These type of insulators are also used as the support insulators for air blast and live tank SF6 circuit breakers

- **Solid Core** - this post insulator is solid porcelain with the metal flanges cemented directly onto the porcelain. Because of the size and thickness of the porcelain, curing of this type of insulator is critical to ensure a high quality product. Improperly cured porcelain will allow for some give, which can progress into circumferential cracking which reduces the mechanical strength. To date, few problems have been found with this type of insulator. These units are installed at all voltages from 7.5kV to 500kV and Hydro One is currently purchasing these insulators from several manufacturers.

- **Conductive/Resistive Glaze type –** post insulators can also be supplied with a semi-conductive glaze, which inhibits arcing, and flashover caused by pollution, contaminants and high humidity. These insulators are known as conductive glaze/resistive glaze (RG insulators). A small current flow over the resistor created on the surface of this type of insulator warms the surface to a few degrees above the ambient temperature. This discourages moisture accumulation. Moisture accumulation is usually necessary to make contaminants conductive. These insulators are installed at selected, high contamination locations

- **Polymeric – these** insulators were developed in the early 1970's and are used in stations rated between the 15kV to 115kV levels. The insulator is constructed around a fiberglass reinforced resin core rod. The outer shell is made from polymeric or silicone based polymeric material. The polymeric type is equivalent in voltage characteristics, strength and physical size to standard porcelain insulators. Silicone base type is equivalent in withstanding contamination to the RG (resistive glaze) insulators. The silicone based insulator releases silicone from its base polymeric material, which encapsulates any contaminates. This hydrophobic property prevents moisture clinging to the contaminants and reducing the dielectric strength. Polymeric insulators are lighter and less susceptible to damage during installation and maintenance than the porcelain type. These insulators are in limited use at Hydro One stations, primarily being applied at the low voltage levels.

Strain Insulators

These are insulators installed on station structures, in either a horizontal or vertical position, and under continuous tension, suspending a flexible wire conductor. Strain insulators may also be installed as mid-span openers. Insulators installed in this manner are not normally electrically stressed, as they are by-passed by a conductor or switch blade and used to sectionalize or isolate sections of a bus or distribution feeder. During the isolation or switching process, the jumper / blade is removed or opened, thereby putting the insulator under electrical stress.

Strain insulator units may be damaged by electrical puncture, cement growth, breakage, or severe deterioration of the porcelain, which weakens the dielectric strength of the insulator string. As the number of defective individual units in the string increases, there is an increased risk of flashover, particularly under stress conditions, e.g. lightning or faults. These insulators may also lose mechanical strength due to cement growth under the cap or around the pin. Mechanical failure can result in the conductor falling on other live conductors or transmission equipment. Because of past failures, mid span porcelain insulators must pass electrical testing before they can be used as electrical isolation. Glass and polymeric insulators installed in this manner do not have to be tested prior being used as isolating points. This makes glass and polymeric the preferred choice for these installations.

Approximately 99% of station strain insulators are porcelain, with the remaining 1% made of glass or a polymeric material. Over 30% of strain insulators in the stations are 50 years of age or greater, and are considered to be at the end of their design life.

- **Porcelain** – these are modular solid heat-treated porcelain insulators with a ceramic glaze surface and metal fittings cemented onto both ends. The metal fittings facilitate connecting individual insulators together to form a string of insulators. The number of units assembled into a string is dependent on the circuit voltage and design standards. The assembled length can vary from 300mm for 7.5kV to 5 meters for 500kV. The strength of the strain insulator is classed as KIP (thousand inch pounds) and is available in 15, 25, 36 and 50 KIP ratings.
- **Glass** These are modular high impact glass insulators with metal fittings cemented onto both ends. Application and rating of glass insulators closely follows that for porcelain but their condition can be more readily assessed. Glass insulators are understood to be in good condition as long as they are visually intact. Glass insulator skirts shatter if there is a defect, making visual inspection a satisfactory test.
- **Polymeric** - these insulators are constructed around a fiberglass reinforced resin core rod. The outer shell is made from polymeric or silicone based polymeric material. Metal end fittings facilitate connecting and mounting of the insulator. The equivalent polymeric must be longer than the glass or porcelain type it replaces. This longer length is required because the polymeric has smaller skirts, which reduces the tracking length and wet/dry creepage distance. Similar to glass, polymeric insulators are understood to be in good condition as long as they are visually intact. The polymeric insulator is much lighter than the porcelain or glass type.

Hydro One and many other utilities have experienced the failure of polymer strain insulators (also called composite or non-ceramic insulators) used as dead-end and as suspension insulators. The root cause of the failures is aging of the rubber material as a result of high electric fields (E-fields) close to the energized end. These failures have raised concern about the health of the insulators remaining in service and stressed the need to determine actions for either life extension or replacement in order to maintain high system reliability. The failure of dead-end insulators poses a larger threat to system integrity than the failure of suspension insulators because failures may result in a downed conductor. In addition, studies have shown that dead-end insulators are exposed to higher E-field magnitudes than suspension insulators. These high E-field magnitudes may result in corona discharge activity that damages the polymer housing and end fitting seal. In the past, most work focused on insulators installed at 230 kV and above, resulting in the use of corona rings at these voltages. Recent experiences indicate that 115- units may be more susceptible because they are generally installed without corona rings and often on structures with closer phase spacing.

2.6 Station Cables and Potheads

Station cables and potheads are associated with equipment located within the confines of a transmission station, such as station service transformer feeds, transformer to switchgear connections, and capacitor bank connections. Hydro One manages transmission station cables and potheads typically with voltage between 13.8 kV to 44 kV. Cables and potheads are typically used when air insulated bus cannot be utilized, because of space limitations.

Transmission Stations cables are typically short (in length) and are usually enclosed, in ducts. Typically, the cables are inspected visually as part of regular station inspection. The inspections include checking for visual evidence of cracks, corrosion, overheating or distortion of the visible sections of the cables and physical damage or compound leaks from the potheads. These practices are consistent with the practices of other leading electric utilities.

Cables consist of the following systems:

- Cables
- Splices/Joint connections
- Potheads and Terminators.

Station cable systems are subjected to a number of stresses. The type of cable selected for each application must normally consider electric, thermal, mechanical and environmental stresses.

2.7 Capacitor Banks

Capacitors are static devices whose primary purpose in power systems is the compensation of inductive reactance of other system components. They are a static source of reactive power on the transmission system that balance the inductive demand on the system and provide the necessary voltage support needed for efficient power transmission.

In general, system operators try to balance the capacitive and inductive demand on the system at all points on the system. The active power portion of the electricity supply is the portion that allows the power system to do work, for instance turn a shaft in a paper mill. The reactive component is a requisite of the power system; and its instantaneous demand quantity must be met at the load.

Most loads are inductive in nature due to the significant use of induction motors for fans, pumps, compressors and other rotating machines. Most electric motors require an inductive component to perform work. With the volume and universal presence of electric motors in our lives, the adequate supply of capacitive VARs to balance the needs of induction motors is necessary for the efficient operation of the electric power supply system. Fortunately, it is possible to produce capacitive VARs by adding shunt capacitors to the system at a reasonable cost.

There are basically two ways that the level of VARs generated on a system may be varied. The first is by manipulating the field excitation of synchronous machines, either motors or generators; the second is to obtain the needed VARs from transmission lines. Using synchronous machines to produce VARs can be inefficient, particularly when the loads are remote from the VAR source. Transmission of VARs over a distance has a price because of the increased losses caused by VAR transmission. Further, transmission of VARs in a power system reduces the system's capability to transmit active power.

All transmission lines produce VARs continuously. Inductive VARs are produced proportional to current levels, and capacitive VARs are produced proportional to voltage. To some extent, voltage levels in lines can be varied to produce the VARs required. During light load hours, e.g. overnight when loads are light and there isn't much demand for inductive VARs, lines can be run at reduced voltage levels to reduce the capacitive demand on the system; the converse is true during peak load hours when the number of motors connected to the system, and thus the inductive demand, is at its peak. Unfortunately, it is often not possible to meet the inductive demand on the system without the addition of shunt capacitors. Further, given that it is more efficient to balance the inductive/capacitive needs of a system at any given point on the system, shunt capacitors often are added at different voltage levels to balance capacitive and inductive VARs out at each voltage level. The reason for this practice is that the greater the VAR demand at any point on the system, the greater the losses at that point. In most systems most capacitive compensation is installed either at the load, or at the distribution voltage level. In lightly loaded systems the level of VAR transport and thus loss at the transmission voltage level is not sufficiently of concern to justify the addition of transmission level capacitors. Hydro One however has a system that is sufficiently heavily loaded as to justify the addition of shunt capacitors at the transmission voltage level at some of the transmission stations.

A capacitor consists of two conductive plates with a dielectric material in between. The closer the plates approach and the thinner the materials the more efficient the capacitor is at producing VARs, and the lower the real power losses. In modern capacitors the plates are in fact thin gauge aluminum foils separated by thin, but effective polypropylene insulating film, impregnated with a non-PCB fluid with high insulating strength. These capacitor packs or elements are then connected together in an appropriate series-parallel arrangement and installed in a stainless steel can and the bushings are welded into position. The primary objective of the can mechanical design is to avoid fluid leakage and corrosion. Capacitor units can be obtained in the voltage range of 120 volts to 27.6 kV, and at VAR ratings ranging from a few kVAR to 625 kVAR. The most common capacitor cans in the transmission and distribution voltage range is 13.8 kV. The Hydro One capacitor banks consist of capacitor cans and interconnecting buses mounted on racks which are stacked on support insulators which are typically mounted on steel support structures so as to be usable at transmission system voltages such as 115 and 230 kV.

Individual capacitor cans, in the past, were either internally or externally fused to ensure that should a capacitor fail it will not cause a can to rupture or cascading failure of the group of capacitors. The more recent development of the fuseless design has resulted in simplification of the bank configuration and has been applied successfully at several locations. The fusing alternatives currently on the Hydro One system are described as follows:

Externally Fused

This design was the technology of choice in Hydro One for many years. Each can has its own current limiting or expulsion fuse to disconnect a failed capacitor can from the bank. When one or more capacitor units are removed, the remaining parallel capacitors are subjected to an overvoltage which must be limited to a maximum value of 110% of rated voltage. External fuses provide a visual indication of a failure but banks tend to be larger, more costly, subject to animal outages and have higher installation and maintenance costs.

Internally Fused

The internal fuses are current-limiting fuses in action. One fuse is connected in series with each element within the capacitor. They are designed and coordinated to isolate internal faults at the element level and allow continued operation of the remaining elements of that capacitor unit. This results in a very small part of the capacitor being disconnected; therefore, the capacitor and the bank remain in service.

Fuseless

As a result of the high reliability of today's all film dielectric, the use of fuseless capacitors (many elements in series), combined with the typical HV banks configuration (many "strings" of capacitor units in series), account for this design's good performance. Some fuseless designs are based on connecting the internal elements in parallel strings, resulting in limitation of parallel energy inside the unit and not imposing restrictions on bank connections or on capacitor can size. A bank containing failed elements can operate continuously and with reduced risk of can rupture. Advantages are reduced installation and maintenance costs, less space, fewer live parts, small animal resistance and lower losses.

In order to make up shunt capacitor installations at transmission voltage levels individual capacitors cans are connected in series and parallel with each other to form capacitor banks, to achieve suitable ratings of reactive power and voltage. Small banks can be seen on distribution lines directly connected through fuses to the phase conductors. At transmission voltages capacitor banks can run to hundreds of MVAR. These capacitor banks are essentially three phase loads, which vary in reactive power and in voltage levels, ranging anywhere between 5.0 MVAR (18 cans) at low voltage level to one of the highest rating worldwide, 411.6 MVAR (1,300 cans) at 230 kV level. Figure 17 shows a typical Hydro One 230 kV ungrounded wye, shunt capacitor bank.

Figure 17: Capacitor Bank

Capacitor banks are connected to the Hydro One transmission system at various transmission stations, depending on the proximity and size of the inductive load to be compensated. Since the inductive portion of the power level that requires compensation varies throughout the day, the amount of capacitance in the system must also be varied. This variance is for the most part achieved by varying the excitation of synchronous machines, and (more economically) by controlling the operating voltage levels of transmission lines through the switching in of capacitor banks. This means that capacitor banks could be switched daily.

2.8 Station Buses

The air insulated station (AIS) buses carry electrical energy from the incoming transmission line terminations to the substation disconnect switches, circuit breakers, transformers, reactors, capacitor banks, feeders and other associated power equipment. The buses operate at voltages ranging from 500kV down to 5kV and typically at continuous currents of up to 4000A. Normally three stranded or rigid tubular bus conductors constitute a single circuit. In most cases one conductor per phase is adequate but for some situations, such as stranded conductors used at 500kV or for very high continuous current requirements, bundled conductors of up to 4 per phase are required. The bus conductors are insulated from, and arranged on support steel structures with sufficient structural strength and clearance dimensions to prevent normal and abnormal operating currents and voltages from resulting in dielectric, thermal or mechanical failure. Rigid buses of either copper or aluminium tubing are supported on rigid support insulators of either the cap and pin or station post design. Strain buses of either copper, aluminium or aluminium conductor steel reinforced (ACSR) are supported by strain insulators.

The modern outdoor air insulated switchyards typically employs a modular, low profile bay design. This modular design concept is based on the idea of having identical bays mounted together in a manner that accommodates both the single line diagram and the available space requirements. The current design relies on the extensive use of rigid aluminium tubular buses supported by station post insulators on tubular support steel sections. The design philosophy results in a reduction in the number of different structural pieces and allows for easier and safer access to electrical components. All rigid bus connectors and other hardware are welded type to achieve higher ampacity ratings. The older high profile bus arrangement primarily consists of stranded strain bus and employs strain insulators supported on lattice type steel structures.

The conductor spacing, line-to-ground and line-to-line and the bus support intervals are determined by a variety of factors. The spacing must take into account the ability of conductors to gallop or move either vertically or horizontally during short circuit, snow, icing or wind conditions. As current passes through the conductor the resistance of the conductor causes its temperature to rise and expansion of its length. This results in increased sag for stranded conductors and increased mechanical loading of terminals, connectors, hardware and insulators supporting rigid bus conductors. Vertical safety clearances between conductor and ground must not be compromised during any abnormal operating or environmental conditions. The bus conductors must have both tensile and ductile properties in order to withstand longitudinal forces and bending movement without failure. Support intervals as well as the electrical and mechanical characteristics of the support insulators must be selected to provide an adequate safety margin when exposed to these abnormal operating and environmental conditions.

2.9 Station Surge Protection

Surge arresters on the Hydro One transmission network protect equipment costing several magnitudes more than the arresters themselves, from the effects of lightning and switching overvoltages. Surge arrester overvoltage protection is employed on the HV and LV terminals of all power transformers, on capacitor banks, at underground cable terminations and on some critical overhead transmission lines. Over the past twenty years Hydro One has replaced the majority of the high voltage rod and pipe gap and silicon carbide arrester overvoltage devices by the more reliable and cost effective metal oxide arresters.

When properly selected, manufactured and configured, they are extremely reliable devices and can offer decades of service without causing any problems. Surge arresters constitute an indispensable aid to insulation coordination in the power systems. The overvoltages caused by lightning and switching surges can cause failures of expensive equipment such as power transformers without the use of arresters The arresters intervene to limit the overvoltages to a safe margin below the rated insulation withstand ratings of the equipment they are protecting.

Arresters being installed today are all gapless metal-oxide (MOA) arresters. The distinctive feature of a MOA is its extremely nonlinear voltage-current characteristic which eliminates the need for the disconnection of the arrester from the line through serial spark-gaps. A leakage current of about 100 µA flows when the normal line-to-ground voltage is applied. Equipment such as power transformers have a standard lightning impulse withstand level (sometimes referred to as "BIL") based on their rated operating voltage, e.g. 900kV BIL for a 230kV rated unit. In accordance with the international standards on insulation coordination, the highest voltage in operation of an oil insulated transformer should stay below this value by a factor of at least 1.15.

The arrester has a rated residual voltage based on a standard lightning impulse test current of 10 kA. This voltage is called the lightning impulse protection level of the arrester. The protective margin of a properly rated and configured MOA located close to the transformer terminal will exceed the minimum international standard requirements by a wide margin. Operating reliability and safety of the MOA has been further enhanced by the adoption of high mechanical strength, explosion and contamination resistant polymeric housings instead of the previous porcelain housings.

Other than the periodic washing required in the more highly contaminated locations, monitoring of leakage current in some special situations and periodic station thermo-vision inspection, there is little or no maintenance required for surge arresters.

Over the past twenty years the failure rate of surge arresters has been considerably reduced by the adoption of the metal oxide technology. The failure prone silicon carbide gapped arresters currently applied on many medium voltage installations are being replaced by the metal oxide technology. Surge arrester replacement is generally integrated with other substation upgrading projects. For surge arresters the issues of degradation and assessment are similar in some respects to those for insulators and some instrument transformers. Methods of assessment and procedures for determining end-of-life based on remnant strength are well established.

2.10 HV/LV Station Structures

The majority of transmission station structures are reinforced concrete, galvanized steel and some wood poles. These are subject to inspection as part of routine substation inspection, typically on a 3-month cycle.

Degradation resulting from corrosion of the reinforcing bars in the concrete can be a very destructive process. Visual inspection can only detect this at a relatively advanced state. Deformation or cracking of the concrete is indicative of an advanced corrosion situation. Treatment is difficult and expensive, involving the removal of the concrete and treatment of the reinforcing bars. In most cases when evidence of such damage is noted the initial reaction is to make short-term repairs. These are not usually very successful and ultimately more significant refurbishment or replacement will be required. End-of-life for these structures can be defined by the presence of widespread damage (cracking of concrete spalling). Other than this, concrete structures would normally only be replaced as part of major substation refurbishment usually initiated by the need for replacement or refurbishment of the major plant or by significant development of the system.

The degradation of steel structures is mainly as a result of corrosion. The rate of degradation is very dependent on the environmental conditions to which the structures are subjected. Industrial pollution is a particular problem for galvanized steel.

For wood poles or structures the issues of degradation and assessment are the same as those for wood poles on overhead lines

2.11 Ancillary Systems - High Pressure Air Systems

Centralized HPA systems are installed at all locations that have a population ABCBs. These breakers employ compressed air as an interrupting and insulating medium. This requires a high-pressure compressed air supply consisting of a centralized HPA compressor/dryer plant as well as an air storage facility. The HPA systems are usually comprised of multi-stage compressors, chemical or heated dryers, numerous air storage receivers, extensive piping and valving arrangements, and controls.

A typical HPA system used by Hydro One is illustrated in Figure 18.

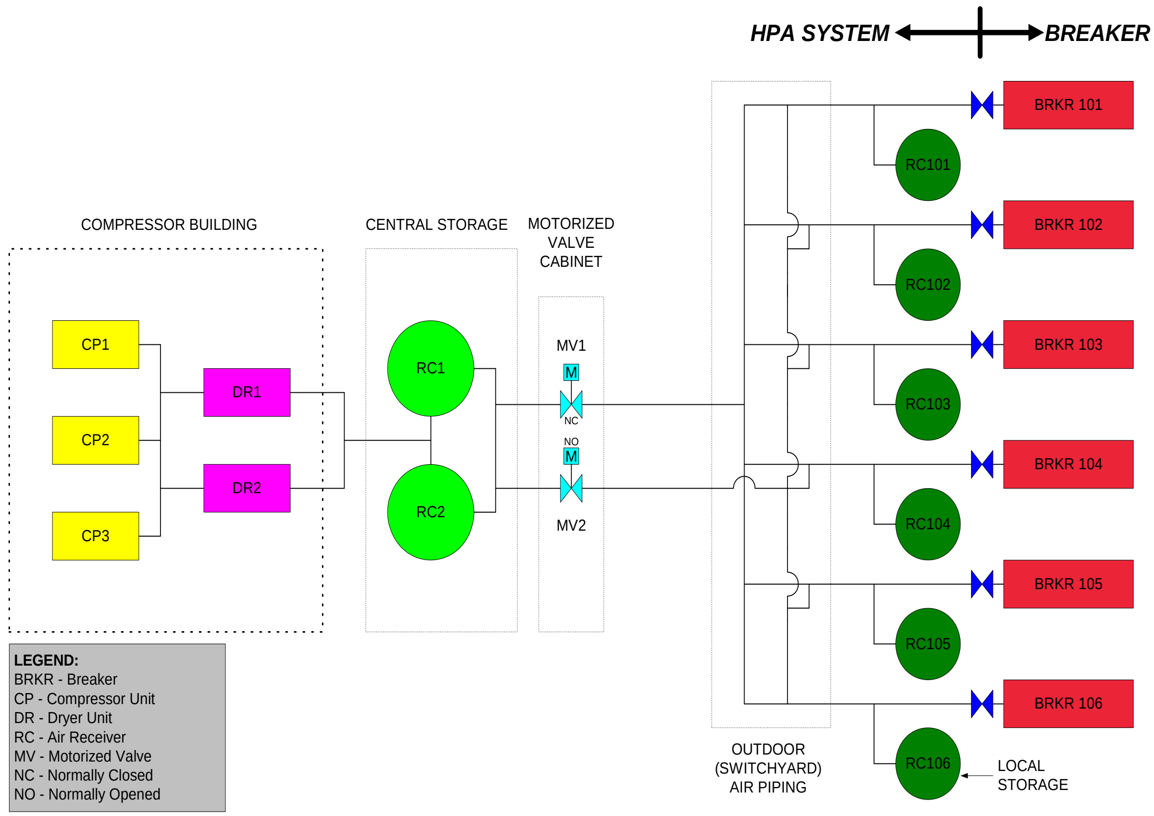

Figure 18: HPA System Block Diagram

Depending on the particular vintage, manufacturer, as well as the specific design, HPA systems operate from between 600 psi (4,143 kPa) to 3600 psi (24,821 kPa).

In order to ensure reliable operation of ABCBs, it is essential that the compressed air is free from contaminants and that it contains minimal amounts of moisture. Since the air, which exits the compressors is 100% saturated with moisture vapour, a reduction of relative humidity is required to make the air suitable for operation. Filtering and drying of the air during and after compression accomplish this. Chemical dryers are now primarily used to remove moisture vapour from the compressed air. Many of the original dryers were "heated-type", where heat was used to dry the air instead of chemical desiccant. These dryers had extensive piping and valving arrangements, which had to be switched manually on a regular basis, making them both prone to leaks and breakdowns, and very labour intensive to maintain and operate. These dryers are now older than 25 years and replacement parts and labour skilled in this old technology are no longer available. Most of these dryers have been replaced with the "heatless-type" or desiccant-based dryers. The dryer units consist of dual chambers filled with activated alumina desiccant, which dry the compressed air as it passes through the desiccant.

Storage receivers are located at the centralized compressor buildings, to ensure an adequate supply of air exists at all times. The criterion for volume availability is defined as the adequate supply for 5 C-O operations of each breaker.

The isolating valves allow portions of the air system to be isolated for maintenance, or redirected in case of a system problem. There are three dominant manufacturers that have supplied valves over the last 30 years. Two of the manufacturers have used a valve design whereby the valve seat, seals both the ball and the body of the valve. Due to this dual function of the seat, many of these valves' body seals leak and need to be replaced.

Storage receivers are located at the individual circuit breakers, to ensure that an adequate supply of air is available to the breaker in the event of multiple, rapid succession operations. Each breaker is provided with enough air for 4 consecutive C-O (close-open) operations. The circuit breaker itself can store 2 C-O operations internally and the local storage receiver holds the other 2 C-O operations.. Following the 4th successive C-O operation, the air for the next operation comes from the central air storage.

Protective devices are required to automatically prevent the supply of energy to the prime mover of the compressor when an abnormal condition occurs during the compressor operation. All air compressors are required to have protective devices for the following:

- High discharge air pressure
- High discharge air temperature
- High discharge cooling water temperature
- Low lubricating oil temperature

Hygrometers are used to measure the dew point at the outlet of desiccant air dryers to insure the air is correctly conditioned.

2.12 Batteries and Chargers

Circuit breakers, motorized disconnect switches, transformer tap changers, and in particular the communication, protection, and control systems in transmission stations must be provided with a guaranteed source of power to ensure they can be operated under all system conditions, particularly during fault conditions. There is no known way to store AC power thus the only guaranteed instantaneous power source in switchyards must be DC, based on batteries. All Hydro One' transmission stations are provided with at least one DC system, comprising a battery, battery charger, and a DC distribution system made up of DC breakers, fuses and associated cable distribution system. Battery systems designated as Station Batteries supply all protection and control and other station ancillary DC services while Telecom designated batteries supply communication system DC requirements at selected stations.

Transmission stations typically have two redundant sources of AC station service power. Bulk Electricity Supply (BES) stations have duplicate station chargers and batteries, whereas Dual Element Spot Network (DESN) stations have only one battery-charger system, in compliance with the requirements of the Northeast Power Coordinating Council (NPCC). The chargers are fed from the AC auxiliary system at 600, 208 volts (3 phase) or 240, 120 volts (1 phase). Typical battery output voltages are 48, 125 and 250 volts. The 48 V battery voltage is usually reserved for communications (Telecom) service, however on the Hydro One system, there is a large number (approximately 70) legacy 48V station batteries used for supply of control panel boards and associated relays. The Station 48V batteries are completely separate and distinct from the Telecom 48V battery systems. The 125V and 250V batteries are used for station protection and control and other ancillary DC services.

A battery charger is an electronically controlled rectifier that is designed to carry the continuous station load over a specified period while simultaneously recharging its battery. The charger has controls that regulate its output voltage to ensure constant voltage irrespective of current output, and current output limits to protect the charger from excessive output demand. It normally also has a boost voltage setting to ensure occasional battery conditioning charging sessions. Chargers are also usually fitted with assorted alarms, including a ground detector alarm for use in ungrounded systems. Figure 19 shows a typical battery charger.

Figure 19: Battery Charger

Transmission stations require rechargeable batteries. There are only two basic types of rechargeable batteries: the nickel–cadmium type and the lead-acid type. In common with most utilities Hydro One use the lead-acid rechargeable cells due to the higher cost and perceived problems with the operation of nickel–cadmium cells.

There are two types of lead-acid cells: lead-antimony and lead-calcium. Hydro One prefers lead-calcium cells due to their longer life, and lower maintenance requirements. Historically, the vented (flooded or wet cell) type battery has been used exclusively by utility users of batteries. A newer type of cell, the valve regulated lead antimony (VRLA) cell was introduced and a number of utilities have migrated to their use because this type of cell has the advantages of a lower space requirement, lower rates of gas evolution, lower safety related costs, and expected lower maintenance requirements. Hydro One has discontinued such installations due to the fact that the life expectancy of valve regulated cells to be significantly less than that of wet cells. Figure 20 shows a typical wet cell battery installation:

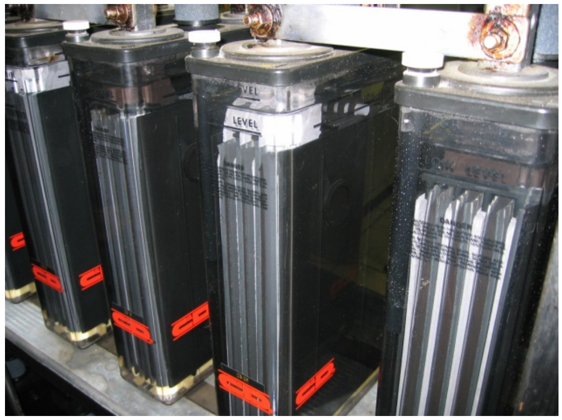

Figure 20: Typical Battery System

The Hydro One standard for battery sizing is in-line with industry standards and ensures that a single battery can carry the entire station load without any AC feed to the chargers for 6 or 8 hour period depending on the station criticality. Typical protection and control battery sizes for step down transformer stations range from 30 to 900 Ampere Hours (AH) while the BES stations are normally equipped with redundant battery systems that range between 180 and 1495AH.

2.13 Station Grounding Systems

Grounding systems are designed to ensure safety of personnel and equipment in and around transmission stations. Grounding systems provide a means of ensuring a common potential between metal structures and equipment accessible to personnel so that hazardous step, touch, mesh and transferred voltages do not occur. In addition, effective grounding systems limit the damage to equipment during faults or surges and they ensure proper operation of protective devices such as relays and surge arresters. The basic design of an effective grounding system is required to:

- Provide grounding of all conductive enclosures that may be touched by public or staff personnel thereby eliminating shock hazards.
- Limit voltage in the electrical system to definite fixed values of step and touch potentials to ensure public and staff personnel safety.
- Limit voltage to within insulation ratings of equipment.
- Provide a more stable system with a minimum of transient over-voltages and electrical noise.
- Provide a path to ground for fault currents to allow quick isolation of equipment with operation of ground fault protection.
- Reduce static electricity that may be generated within the facilities.
- Provide protection from large electrical disturbances (such as lightning) by creating a low resistive path to earth.

The Canadian Electrical Code (Sections 10 and 36) and IEEE Guide for Safety in AC Station Grounding (IEEE STD 80) stipulate the requirements for the design of these systems. Hydro One has followed its own standard "Ontario Hydro Transmission and Distribution Grounding Guide, 1994" for design of these systems at its stations.

Soil resistivity measurements at the station location are a required to design an adequate grounding system. Once the grounding system has been installed, it is tested and verified with 'fall of potential' measurements.

Over the period that Hydro One' transmission stations have been in existence there have been some changes in the applicable standards. These, in general, have led to reductions in the permitted maximum potential rise and in step and touch potentials. However, the biggest change during this period has been the ability to accurately model the effectiveness of grounding systems. Traditional "manual" calculations will have been used to design many of the existing stations. These were not able to provide complete definition of potentials and fault conditions. Grounding system installations are typically classified as permanent or temporary systems, as described below.

Permanent Grounding Systems

Grounding systems are comprised of predominantly copper conductors connected together into a mesh that is buried and bonded to all station structures. A typical station grounding system is depicted in Figure 21 and consists of the following:

- 4/0 AWG bare copper conductors buried 12 to 18 inches below grade in a grid pattern that are spaced 10 to 20 feet apart.
- At ground conductor crossings, the conductors are securely bonded to each other.
- Ground rods are securely bonded to the grid at corners, and at junction points along the perimeter. Redundancy in these connections is a requirement.
- Fences, buildings (control, maintenance or administration) are tied to the main grid as well as to water service pipes.
- Any outgoing circuit shield wires and cable shields, as well as station fence ground are also bonded to the station ground grid.

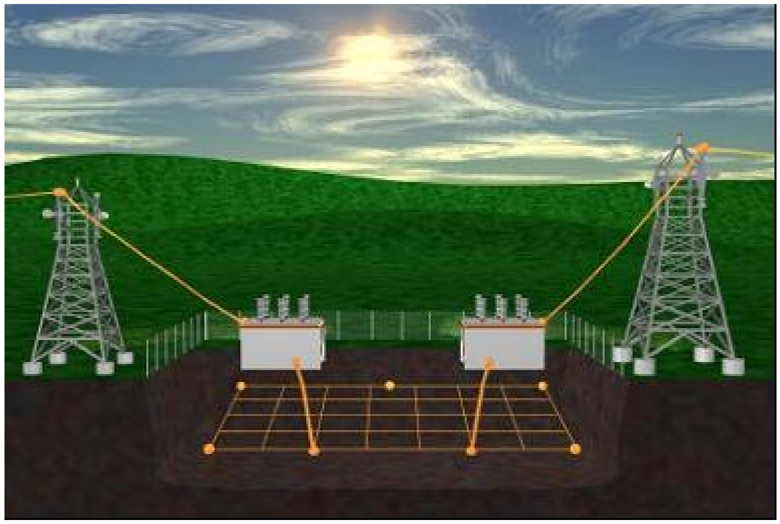

Figure 21: Typical Station Ground Grid

All above grade metallic facilities including structures, transformers, breakers, and fencing would be securely bonded to the grid with grounding conductors as shown in Figure 22. Additional ground rods would be securely bonded to the grid at major facilities and particularly at surge arrester locations. One type of service that is normally isolated from the ground grid is telephone service using metallic pair cable. Such cables are typically isolated from ground in order that exterior telephone equipment is not damaged by the high voltage spikes that are observed in ground grids during faults.

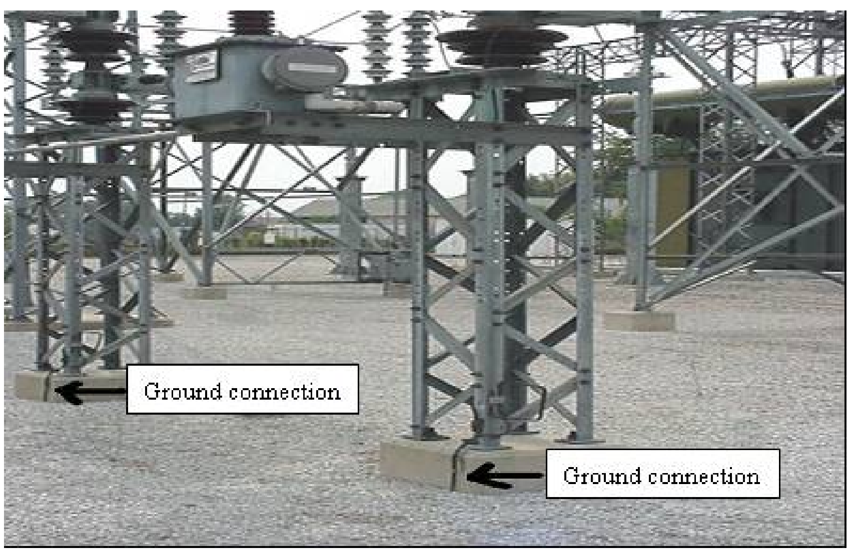

Figure 22: Typical Ground Connection of Switchyard Structures

The station security fence may, or may not, be bonded to the station ground grid depending on several factors such as the minimum distance from the fence to grounded station equipment, whether a rail siding enters the station or whether the gates incorporate telephones, card readers or electric gate locks.

Temporary Grounding Systems

Temporary grounding and bonding systems are installed for personnel safety when working on de-energized apparatus. These are required to eliminate hazardous induced potential differences caused by adjacent energized conductors, residual charges on capacitive circuits or accidental re-energization of circuits or apparatus.

2.14 AC/DC Station Service Equipment

All Hydro One transmission stations are provided with designated AC and DC station service systems. These are the supply systems that provide AC power to the auxiliary equipment in the station such as battery chargers, fans, pumps, HVAC and lighting and DC power from the batteries to control, metering, telecommunication, SCADA, circuit breaker and switch control and operation.

The rating and configuration of these station service systems depends on the function, criticality and rating of the specific transmission station. The stations are categorized as bulk electricity system (BES) stations and dual element spot network (DESN) step down transformer stations. Several of the station service systems are dual feed arrangement to ensure reliability and to minimize the impact of any local supply problems. In all cases, any loss of supply would automatically trigger an alarm.

DC Station Service

The DC station service (DCSS) supplies critical transmission station protection, control and annunciation equipment that operate (trip and close) circuit breakers, circuit switchers, motor operated disconnect switches and emergency lighting.

The main components of DC Station Service distribution system (excluding the batteries and chargers which are evaluated in a separate document) are transfer switches, main and subordinate distribution panels, cables, fuses and other service breakers etc. The DC station service must remain functional for a period of time (6-8 hours) after the initial loss of the charger supply, and capable of operating breakers to re-establish AC supply at the end of that period.

Typical battery output voltages are 48, 125 and 250 volts. The 48 V battery voltage is usually reserved for communications (Telecom) service, however on the Hydro One system, there is a large number (approximately 70) legacy 48V station batteries used for supply of control panelboards and associated relays. The Station 48V batteries are completely separate and distinct from the Telecom 48V battery systems. The 125V and 250V batteries are used for station protection and control and other ancillary DC services.

The DC Station Service reliability requirements are determined based on compliance with regulatory and planning requirements For bulk electricity system (BES) stations, the DC station service design requirements must comply with the TSC, NPCC and IESO to maintain the adequacy and security of the transmission system. The design of the station service system shall ensure that if either the battery charger fails or the AC supply source fails, the station battery bank shall have enough capacity to allow the station to operate for at least eight hours for a single battery system or at least six hours for each of the batteries in a two battery system.

Hydro One is obligated to comply with various NERC Standards and NPCC Criteria related to emergency operating procedures and system restoration. More specifically, the NPCC Criteria Document A-03 "Emergency Operation Criteria", section 4.10.1 (System Restoration - Testing Requirements), details a number of tests that must be performed regularly at certain stations to ensure that facilities are available when required. Hydro One has identified a total of 70 stations that are on the list of key facilities needed to initiate restoration following a blackout (Basic Minimum Power System, BMPS).

The DC station service must ensure a high degree of dependability and must ensure that no single contingency or common mode failure results in the loss of critical relay protection or automatic tripping of power circuit breakers. This is achieved by having duplicate battery banks and rectifier / charger sets ("A" and "B") ,each capable of supplying the **total** DC station load, with a DC transfer scheme to switch the supply between the "A" and "B" sources.

For BES stations, this requires that "n-2" system design criteria be applied to the design of the DC station service. That is for pre-contingency planned or forced outage of the station "A" battery or associated charger or AC supply source, loss of a subsequent DC supply element (i.e. "B" battery or associated "B" charger or AC supply source) must not result in loss of critical relay protection or automatic tripping of power circuit breakers.

For Dual Element Spot Network (DESN) transformer stations a single battery / charger system is to be used. AC supply to the charger is to be from an automatic transfer switch fed from both AC station service panels. The single station battery must have enough capacity to allow the station to operate for at least eight hours following the loss of the charger or the AC supply source.

Where a single battery system is used, the following conditions shall be met:

a. It can be tested and maintained without removing it from service;
b. Each protection system shall be supplied from physically separated and separately fused direct current circuits;
c. No single contingency other than failure of the battery bank itself shall prevent successful tripping for a fault.
d. Critical DC supplies shall be monitored and annunciated such as relay protection circuits and high voltage interrupters (HVIs).
e. For tap transformer stations, one protected (fuse/breaker) monitored DC station battery system is required unless two systems are provided.

The Transmission System Code (TSC) Section 10, "Protection System Requirements" requires that telecommunication battery and DC system design shall ensure that systems are:

(a)designed to prevent unwanted operations such as those caused by equipment or personnel,
(b) powered by the station's batteries or other sources independent from the power system, and
(c) monitored in order to assess equipment and channel readiness.

DC transfer switching refers to the station service level transfer of DC load supply from its "normal" supply source to an alternate source of supply following an equipment outage (and loss of the "normal" supply) or for the purpose of carrying out maintenance. Hydro One currently has three types of DC transfer schemes installed; these are:

(i) **Automatic:** Upon loss of "normal" supply this scheme automatically transfers to an alternate source of DC supply.

(ii) **Semi-Automatic:** Operator intervention is required once to transfer to an alternate source of DC supply.

(iii) **Manual:** Operator interaction is required to transfer load supply to an alternate source of DC supply.

AC Station Service Systems

All transmission stations (BES and DESN) have at least two redundant AC station service systems comprising station service transformers, fuses, LV circuit breakers, transfer switches, load centers, panelboards and associated cable distribution system. An additional third source of AC station service such as diesel generators or supply from the local area distribution system must be provided for Bulk Electricity Supply (BES) stations

Hydro One reliability requirements for AC station service systems are established to comply with regulatory requirements of the Ontario Transmission Code, NPCC criteria for bulk power and interconnected system protection, design and operation and also with the requirements of the Independent Electricity System Operator (IESO)of Ontario

In general requirements for bulk power system facilities are that there shall be two sources of station service AC supply, each capable of carrying at least all the critical loads associated with protection systems.

For existing BES stations there are two common variations of the standard AC Station Service supply configuration. The configuration for the larger existing BES stations, having more than two autotransformers consists of three independent sources of AC supply and LV switchgear configured to provide supply to four main AC load distribution centres/panels. Another variation also incorporates three sources of AC supply but provides supply to two main AC load distribution centres/panels

In the future the new, larger BES stations will be supplied by three independent sources but with a less complex and cost effective switchgear configured to supply three load centers/panels only. For new BES Switching Stations or new BES Stations with two or fewer autotransformers, the standard configuration requires that only two independent AC sources of supply be provided to supply two main AC load distribution centres/panels

For DESN stations the configuration provides two independent AC station service supplies connected so that an outage to a single element will not result in the prolonged loss of both supplies. An emergency connection between the AC supplies is provided so that either supply can be connected to supply the entire station service load. New DESN stations are being supplied by simpler and more cost effective load transfer switchgear.

AC transfer switching refers to the station service level transfer of AC load supply from its "normal" supply source to an alternate source of supply following an equipment outage (and loss of the "normal" supply) or for the purpose of carrying out maintenance. Hydro One currently has three types of AC transfer schemes installed; these are:

(iv) **Automatic:** Upon loss of "normal" supply this scheme automatically transfers to an alternate source of AC supply.

(v) **Semi-Automatic:** Operator intervention is required once to transfer to an alternate source of AC supply.

(vi) **Manual:** Operator interaction is required to transfer load supply to an alternate source of AC supply.

To comply with regulatory requirements that specifies eliminating the possibility of a single contingency or common mode failure disabling the entire AC system, fully automatic AC transfer schemes are to be avoided or eliminated. Manual only AC transfer schemes are also to be avoided for switching safety reasons.

The standard for all new and replacement installations requires semi-automatic AC transfer schemes to be provided with remote-OGCC and remote-local initiation and full manual mode override capability. Simple, double throw positive action, automatic transfer switches are to be used downstream of the station service supplies and directly for essential/critical AC loads (e.g. transformer cooling, circuit breaker heaters and auxiliaries, battery chargers). All AC transfer switching schemes use "Break-Before-Make" type switching to prevent paralleling of station service sources.

Each DESN TS has two independent AC station service supplies fed from adequately rated station service transformers connected separate buses on the LV switchyard and arranged so that an outage to a single element will not result in the prolonged loss of both supplies.

The station service transformer ratings are selected to cater for the ultimate DESN TS loads. The secondary system is 120/208V, 3-phase, 4-wire. The transformers are typically rated at 200kVA, with a secondary voltage of 120/208V, 3-phase. Typically there is a 600A transfer switch connection between the two AC supplies is provided so that either supply can be connected to supply the entire station service load.

2.15 Station Buildings

Hydro One owns a number of buildings of different types and sizes, located in or adjacent to transmission stations, and spread throughout the province. These buildings can generally be categorized as:

- Control Buildings
- Auxiliary Systems Buildings
- Occupied Buildings
- Ancillary Buildings.

The Control Buildings are used primarily to house protection and metering equipment, batteries, and control and communication systems. Auxiliary Systems Buildings are buildings used for housing technical equipment such as metalclad switchgear, air compressors and dryers, and oil processing and storage equipment. Occupied buildings include maintenance centers, operation centers, and offices. Ancillary buildings include garages, stores etc.

These buildings have been constructed over a long period of time to meet the particular needs of the time and constructed in accordance with required building standards. Thus, the buildings consist of a wide variety of designs and construction materials e.g. size varies from less than 100 sq. ft. to several thousand sq. ft. depending on the application and these may be made from ornamental brick, concrete block, engineered metal or other prefabricated material.

2.16 Fences

It is Hydro One's practice to erect security fences around their electrical plant facilities, including transmission stations and exposed high voltage cable terminations. This practice is for the purpose of protecting the public from hazardous electrical contacts, and to protect these facilities against intrusion and vandalism.

Types of Fence

The security fences can be of several types such as steel chain link, aluminum chain link, wood, masonry and Durisol. All the above types of fence have been installed at transmission stations owned by Hydro One. Chain link fences are by far the most widely used type of fence and constitute about 99% of the total length of fence installed. This type of fence comprises fence fabric, galvanized support posts and top rail, bottom tensioning wire, barbed wire on top, support brackets, concrete foundations, gates, warning signs and grounding mechanisms. The fence fabric is generally galvanized steel, but aluminum fabric is also used in certain cases.

The other types of fence such as walls of either solid masonry, metal or Durisol may provide an additional degree of security. Solid walls are generally more difficult to breach and also prevent a direct line of sight to equipment inside the station. Solid walls may also prevent vandalism from outside the fence, such as by projectiles (e.g. rocks). The probability of such damage actually occurring depends on a number of variables including the height of the wall, surrounding terrain, and elevation of the equipment inside the station. The material utilized for this type of fence is generally commensurate with the evaluated security risk of the area. As stated earlier, most of the fences at the stations owned by Hydro One are of the chain link type.

Technical and Legal Requirements

The minimum design height of the fence specified by Ontario Electricity Safety Code is 1.8 metres. The standard fence design adopted by Hydro One follows IEEE Standard C2-1997, which requires a minimum chain link fence height of 2.13 metres of fabric, with an additional 0.3 metres extension composed of three-strands of barbed wire at the top. The other important requirements in fence design are: the gap under the fence, between the fence and grade must be less than 25 mm, a 50 mm maximum gap between the gate pipe frame and the gate support posts, and lastly a proper grounding system for the safe grounding of the fence.

Gates are provided at suitable locations around the fence to allow access to authorized persons and vehicles. Depending on security requirements at a particular site, the gate control mechanism is designed to provide one of: automatic vehicular access, manual vehicular/personal access, manual personal access, or manual vehicular access.

In order to warn the public of the danger and to discourage entry by unauthorized persons, approved danger and warning signs are posted at all gates that allow access to transmission stations and other hazardous locations. Such signs are further posted at regular intervals (normally 10 m) along the fence.

2.17 Station Fire and Security Systems

The Security and Fire Protection asset class includes systems for protection of transmission facilities from the threats of fire, break-ins and vandalism. Hydro One owns a large number of transmission stations and buildings of different types and sizes and has installed some form of security and fire prevention measures for protection of the various facilities at each of these locations as described in this Asset Description.

Security Systems

The primary physical barriers provided at all locations to prevent unauthorized entry into Hydro One facilities are the site perimeter fencing or walls. These fences and walls constitute a separate asset class, and thus are not further discussed herein. The security systems in the asset category include additional measures ranging from conventional simple door control security systems to video surveillance facilities.

The form and degree of sophistication of the security systems at these stations/buildings varies widely. The primary reason for this degree of latitude being that, in the beginning, security systems at many locations were installed as a result of 'reactive after the fact' approaches following incidents. Another factor to consider is that a significant number of stations in the past were manned thus no extra security arrangements were required. This is no longer the case. Security requirements have therefore changed in recent years resulting in a need to develop a strategy for standardization for security systems. This standardization process is still in the evolving stages.

Generally, three types of security systems have been employed at transmission stations. The simplest types include simple door and gate control systems, often padlocks, to permit entry to authorized personnel only, and motion sensor triggered lighting installations. Note that in many cases, there are third parties that have access to the station premises. Typically, the third party installs its own lock and opening either lock provides access to the site. A first step in enhancement of the security level at transmission and distribution stations is the replacement of the locks and the implementation of a new key management system to control access to the sites. The second types include motion detection and alarm systems within buildings. The third type includes microprocessor surveillance of the motion detection and modern slow scan video surveillance systems, with both of these types of systems wired to supervisory control and data acquisition systems (SCADA) to allow central monitoring. The latter types of systems are installed at only a few sites at present.

At a number of locations, security monitoring is part of the fire detection system or the heating, ventilation and air-conditioning system. Hydro One has control centers at 10 locations; and each of these centers monitors a number of stations. As part of the development of a standardized security policy and system, it is planned to centralize the monitoring function to a master control centre.

Fire Protection Systems

Fire protection systems at transmission facilities are primarily of two types; those associated with buildings and those associated with equipment.

2.18 Buildings and Indoor Equipment

In a manner similar to the practices followed by Hydro One for security systems no standardized practices for fire detection and prevention have been established for general building areas. Buildings constructed after 1985 have fire detection systems installed; whereas some of the older buildings do not have even simple smoke detectors. Other types of systems installed for fire control in buildings include:

- Carbon dioxide based systems
- FM 200 systems. These have replaced the now unacceptable Halon based systems that had been installed at some locations.
- Sprinklers. These are normally installed in all basements with areas over 300 square feet.
- Fire hoses connected to municipal water systems are provided inside some buildings.

Certain indoor equipment, such as oil-filled transformers and oil-filled cable potheads, require dedicated fire protection systems such as water deluge systems with associated hose cabinets. Such systems are provided to meet the requirements of National Fire Protection Association (NFPA) Standard No. 15; and they include fully automatic air supervised, or electrically supervised, cycling type, dry pipe, open head deluge systems for all major indoor fire hazards, such as those noted above.

Deluge systems generally consist of open head spray nozzles attached to a piping system that is connected to a water supply through a deluge valve. The valve is opened by the operation of a fire detection system installed in the same area as the nozzles. When this valve opens, water flows into the piping system and discharges from all nozzles. This type of system uses high-velocity water sprays of a relatively large droplet size directed against convection air currents; and the system is designed to extinguish fires on, under, or immediately around protected equipment.

Outdoor Equipment

Oil filled transformers in outdoor stations are equipped with fire detection systems. The monitoring of heat detectors is handled through SCADA systems to the respective control centres, or through the dedicated fire detection panel to the SCADA system and then to the control centres. Only a few transformers, at attended, rather than unattended, Stations, are without this system. Other outdoor equipment, with the exception of oil filled cable terminations are not considered vulnerable to fire and thus they are not fitted with fire detection systems.

2.19 Station Drainage, Oil Spill Containment and Geotechnical Systems

The Transmission Drainage and Geotechnical asset class includes drainage facilities for the removal of surface and ground water, and civil work facilities such as roads, yard compaction and surfacing, and footings.

Drainage Systems

Transmission and switching stations require drainage facilities for the removal of surface and ground water. Drainage is a practical and economical way of improving and maintaining firm, dry, stable sub grades for support of roads, railways, and foundations for structures and buildings.

The two basic sources of subsurface water are the presence of a high ground water table, and precipitation (rain or snow melt) seepage into the soil. When water seepage encounters an impervious layer of soil, water is retained and forms pools, which increases the ground water table level. Occasionally, subsurface soil formations result in upward water flows, or springs. These, when they occur within stations, must be capped and the water diverted off site to ensure the water doesn't compromise the subsurface soil integrity, or cause grounding problems. Foundation under-drainage protects basement slabs against hydrostatic uplift and flooding of basements. Road under-drainage helps to minimize frost heaving and frost boils. Inadequate drainage can compromise maintenance and construction access for heavy equipment; and thus can cause a personnel safety hazard.

Many stations have drainage systems, which consist of main drainage and under-drainage. Main drainage is a system of catch basins, buried piping and manholes, including necessary pumps, all as required to suit the station site. The system also includes connections for building rainwater drains and transformer oil spill containment system drains. Under-drainage consists of buried perforated piping connected to the main drainage. This type of drainage pipe is provided to allow drainage of sub-surface water from graded areas, roads, parking areas, railroads and cable trenches. Sumps and sump pumps are included in under-drainage systems, where required.

Many stations exist without a main, or under-drainage systems. In such cases, runoff percolates over the yard surface, which is sloped to ensure drainage, and the water finds its way to a ditch off the station active surface.

Over the past 20 years there has been growing awareness of the need to contain oil spillage from major plant. Growing awareness of environmental issues and tightening of legislation and increased penalties have forced electric utilities to address this issue in a more systematic and consistent fashion. Prior to this period, oil containment was a feature for major transformers but the application was varied and non-uniform. Over the past 20 years, the onus has been on ensuring that the oil containment systems for all major transformers are to a uniformly high and acceptable standard.

Transformer spill containment systems are operated to release runoff to drainage systems, except during oil spills when the containment connection is shut off by a special pump located in a sump. This sump may be connected to one or several spill containments; and it is not considered part of the drainage system.

Maintenance and ongoing management of oil containment systems is generally limited to visual inspection as part of routine substation inspection with functional checks on pumps used to remove rainwater. As part of the program to ensure that oil containment systems are to a uniformly high and acceptable standard, an overall assessment of their condition would have been undertaken resulting in upgrading or replacement as necessary. As most systems will therefore have been subject to relatively recent assessment, and if necessary upgrade/refurbishment, condition based end-of-life would not normally be considered a significant issue. However, if a major defect or damage was detected during routine inspection a full assessment, and if necessary appropriate repair or replacement, would be undertaken.

Layout of a typical drainage system for a Hydro One station is shown in Figure 23.

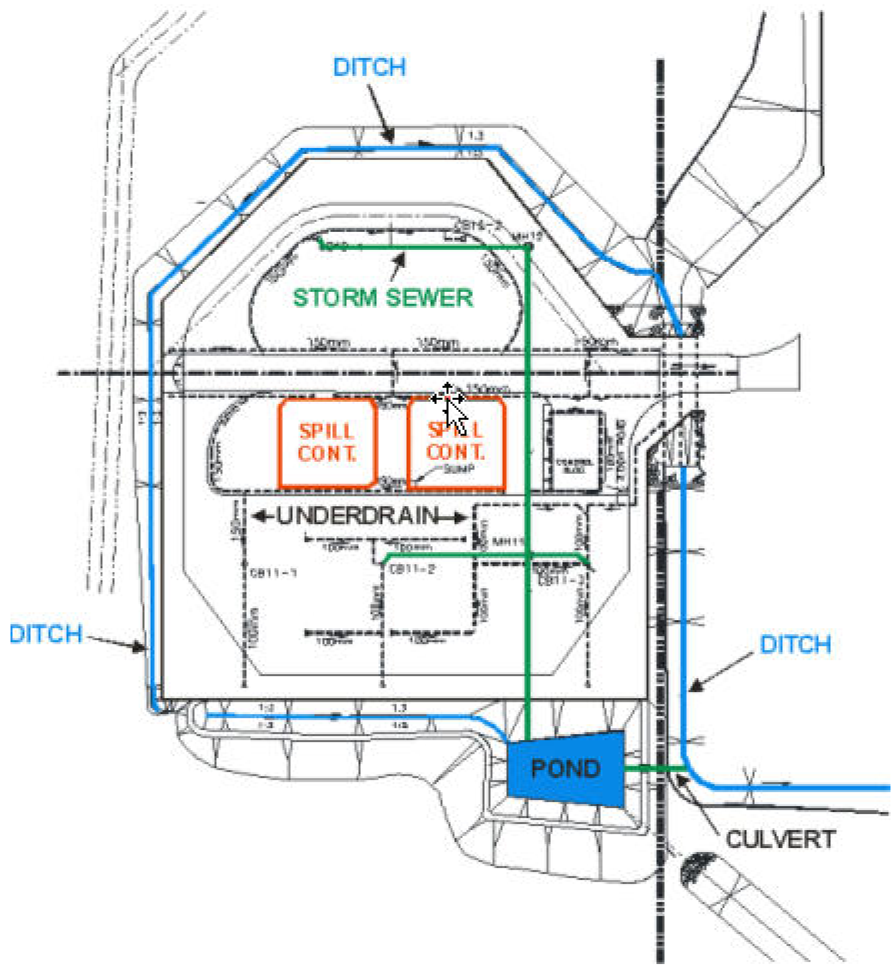

Figure 23: Components of Drainage Systems

2.20 Yards

Transmission station yards, when first constructed must initially be stripped, compacted, and graded. Stripping involves removal of the vegetation including roots and top soil, including all undesirable other soil elements, such as rock, boulders, organic materials, and scrap, as well as items such as bog and quicksand. After the removal of undesirable soils elements is completed, the site is graded to the final design sub-surface elevation(s). This generally involves movement of subsurface soils from some areas of the site to other site areas and occasionally the addition of extra fill, or removal of unneeded fill. Drainage, including ditches around the site would be added at this point in the process. During the process of grading the site is also compacted to ensure soils stability and bearing capability. The last stage in yard preparation is the addition of suitable toppings, such as crushed rock to ensure a high resistance cover over the ground grid.

Guidance during this process is provided by the interpretation of geotechnical tests carried out prior to the start of site works. These tests involve drilling and excavations of soils at site as well as extensive analysis of the soils to determine their suitability for inclusion in the final site subsurface.

2.21 Roads

Roads into and inside station sites are conventionally divided into two types, surfaced and un-surfaced. Both types of road are built in approximately the same manner up to the final surface layer. The sub-surface layers are specially compacted and normally special fill is brought in to ensure sufficient subsurface bearing capacity is provided. Occasionally, special geotechnical fabrics are installed below the road to ensure adequate bearing capability. Un-surfaced roads are finished with gravel to provide a drivable surface. Surfaced roads are conventionally surfaced with asphalt, or sometimes concrete.

2.22 Footings

Footings for equipment support are almost always made out of reinforced concrete. Very occasionally in locations where soils conditions are poor pile foundations are provided, with a variant of this type of foundation provided by the use of screw anchors. It is understood there are very few piled foundations, and no screw anchor foundations used within the Hydro One system. A typical footing is shown in Figure 24.

There are two basic variants for the installation of footings. One involves excavation of the entire site and then the installation of the footings at the base level, with soils installed and graded from this level. The other involves excavation into the compacted sub-grade and installation of the foundations in the sub-grade materials. Footings installed in this manner may either be excavated or they may be augured. Auguring is generally preferred on a cost basis; but both are viable methods of footing excavation. The first type of foundation installation practice is generally only used in granular soils; the second type, the excavated or augured type, is generally used in more cohesive soils, such as clay.

Footings of course must be carefully designed to match the soils in which they are placed and also they must be adequate for the ultimate loads they must carry, under extreme conditions of weather as well as electromechanical loadings. Appropriate safety factors are always applied.

Figure 24: Damaged Footing of a SF_6 Bus Duct

3.0 Stations Asset Demographics

This section provides demographics data for major power system assets that are found at Hydro One Stations excluding Protection and Control assets.

3.1 Oil Circuit Breakers - Demographics

Hydro One Hydro One Inc. (Hydro One) has 2,001 Oil Circuit Breakers (OCB) in its transmission substations operating at voltages up to 230 kV. Approximately 70% of these are providing service at voltages below 50 kV, 19% at 115 kV and the remaining 10% at 230 kV. The majority of these OCB (60%) are 20 to 40 years old and about 17% are more than 40 years old as shown in Table 2. Table 2 also illustrates the demographics of OCB with respect to age (original installation or refurbishment date).

		Voltage Class				
		<50 kV	115 kV	230 kV	Total	(%)
Age Group	0-10yrs	69	34	9	112	5.60%
	11-20yrs	238	138	23	399	19.94%
	21-30yrs	163	16	27	206	10.29%
	31-40yrs	467	73	109	649	32.43%
	41-50yrs	366	73	33	472	23.59%
	>50yrs	105	49	2	156	7.80%
	Unknown	7	0	0	7	0.35%
	Total	1415	383	203	2001	100.00%
	(%)	70.71%	19.14%	10.14%	100.00%	

Table 2: Oil Circuit Breaker Demographics

The last oil breakers were purchased in 1983, after which manufacture effectively ceased. In the 1990s, with the assistance of the original manufacturers of the OCB Hydro One began a program of “remanufacturing” some of its oldest OCB. These breakers were designated as “new” from an accounting standpoint and are the group shown as being up to 25 years old in Figure 25. Hydro One remanufactured 431 breakers of various ratings were before the program was ended and the remanufacturing facilities were closed down. Spare parts remain available from third parties but technical support from OEMs is no longer available.

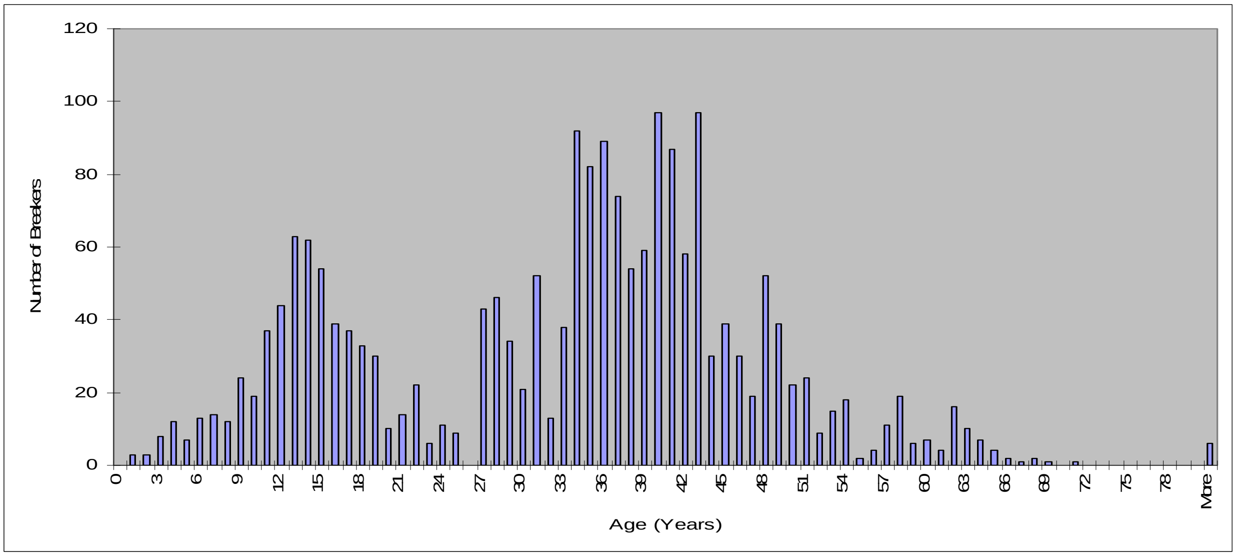

Figure 25: Age Breakdown of Oil Circuit Breakers

3.2 SF6 Circuit Breakers - Demographics

Hydro One has 1254 SF_6 free standing circuit breakers in its transmission stations operating at voltages up to 500 kV. Approximately 64% of these are providing service at voltages below 50 kV, 11% at 115 kV, 22% at 230 kV and the remaining 3% at 500 kV as shown in Table 3.

		Voltage Class					
		<50 kV	115 kV	230 kV	500 kV	Total	(%)
Age Group	0-10yrs	94	33	115	14	256	20.41%
	11-20yrs	328	37	45	12	422	33.65%
	21-30yrs	210	19	45	10	284	22.65%
	31-40yrs	0	10	9	0	19	1.52%
	41-50yrs	1	0	0	0	1	0.08%
	>50yrs	0	0	0	0	0	0.00%
	Unknown	163	42	60	7	272	21.69%
	Total	796	141	274	43	1254	100.00%
	(%)	63.48%	11.24%	21.85%	3.43%	100.00%	

Table 3: SF_6 Free Standing Circuit Breaker Demographics

3.3 Air Blast Circuit Breakers - Demographics

There are a total of 223 Air Blast Circuit Breakers (ABCB) on the Hydro One' transmission system representing approximately 5% of all the circuit breakers Hydro One owns. Table 4 show the age demographics of ABCB by voltage class. As can be seen from the table, ABCB are mostly used on 230 kV systems, with more modest applications at 500 kV, 115 kV and at voltages below 50 kV. There are 192 HV (at 115 kV or above) and 31 LV ABCB installed on Hydro One's system, mostly built between 1950 and 1982.

		Voltage Class					
		<50 kV	115 kV	230 kV	500 kV	Total	(%)
Age Group	0-10yrs	0	0	0	0	0	0.00%
	11-20yrs	0	0	0	0	0	0.00%
	21-30yrs	2	0	12	0	14	6.28%
	31-40yrs	0	2	60	50	112	50.22%
	41-50yrs	18	0	68	0	86	38.57%
	>50yrs	11	0	0	0	11	4.93%
	Unknown	0	0	0	0	0	0.00%
	Total	31	2	140	50	223	100.00%
	(%)	13.90%	0.90%	62.78%	22.42%	100.00%	

Table 4: Air Blast Circuit Breakers Demographics

3.4 Gas Insulated Switchgear (GIS) - Demographics

There are three 500 kV, five 230 kV and one 115 kV GIS currently in operation on the Hydro One system, with the oldest being commissioned in 1977. In addition, there are four medium voltage GIS installed on the Hydro One system, all within the past three years.

There are 55 LV (50kV<) and 109 HV SF_6 circuit breakers, associated switches, buses and ancillary equipment currently installed in Hydro One gas insulated substations. A circuit breaker bay (CBB) is considered to be the 3-phase assembly of a circuit breaker, and its associated disconnects and ground switches, instrument transformers, and interconnecting buses. Circuit breakers installed on the LV GIS are all of the vacuum technology.

3.5 Metalclad Switchgear - Demographics

As tabulated in Table 5, there are 753 metalclad switchgear installations on the 13.8kV and 27.6kV systems.

MetalClad Breaker		Voltage Class			
		13 kV	27 kV	Total	(%)
Age Group	0-10yrs	36	48	84	11.16%
	11-20yrs	121	28	149	19.79%
	21-30yrs	223	26	249	33.07%
	31-40yrs	109	0	109	14.48%
	41-50yrs	44	0	44	5.84%
	>50yrs	16	0	0	0.00%
	Unknown	79	23	102	13.55%
	Total	628	125	753	100.00%
	(%)	83.40%	16.60%	100.00%	

Table 5: Metalclad Switchgear Demographics

Approximately 85% of the Hydro One switchgear population is operated at the 13.8 kV voltage level and the remainder is 27.6kV voltage levels. About 50% of the switchgear assemblies are over 25 years old. Expected life for metalclad switchgear is 40-50 years

3.6 Transformer - Demographics

Hydro One owns 1,467 transmission transformers. This asset class covers a wide range of transformers, which vary in terms of voltage ratings, power ratings, functions, etc. The following functional groups are included under the transmission transformers asset class. For clarity throughout the document, these groups are consolidated to form three main functional groups.

Group 1:

- Autotransformers:
- Two and three winding transformers
- Phase shifting transformers
- Shunt Reactors
- Grounding transformers.

Group 2:

- Regulator transformers
- Grounding transformers

Group 3:

- Station Service Transformers
- Miscellaneous transformers.

Table 6 shows the demographics of Group 1 transformers.

Group 1 - Transformers

		Age Group								
	Voltage Class	0-10yrs	11-20yrs	21-30yrs	31-40yrs	41-50yrs	>50yrs	# Unknown	Total	%
Autotransformers	115kV	0	0	0	0	1	5	0	6	
	230kV	7	9	11	17	24	21	0	89	
	345kV	0	0	2	1	1	0	0	4	
	500kV	7	9	4	15	8	0	0	43	
Sub-Total		14	18	17	33	34	26	0	142	18.6%
2-3 Winding Transformers	115kV	34	16	18	40	49	144	0	301	
	230kV	25	44	42	104	64	8	0	287	
Sub-Total		59	60	60	144	113	152	0	588	76.9%
Phase Shifters	230kV	0	2	0	0	1	0	0	3	
	regulator - 230 kV	0	0	0	2	0	0	0	2	
Sub-Total		0	2	0	2	1	0	0	5	0.7%
Shunt Reactors	<50kV shunt	0	4	3	7	4	0	12	30	
Grand Total		73	84	80	186	152	178	12	765	
%		9.5%	11.0%	10.5%	24.3%	19.9%	23.3%	1.6%	100.0%	

Table 6: Ages and Voltage Breakdown of Group 1 Transformers

The transformers in this group are used on all voltage levels up to 500 kV but a predominant 96% are installed in the 115 kV and 230 kV systems. Not counting the # of unknown age, approximately 23.3% of the transformers in this group are over 50 years old.

Group 2 - Regulator transformers

The second group of transformers includes regulator transformers and grounding transformers. Table 7 shows the age breakdown of these transformers. Not counting the # of unknown age, a total of 54.4% of these Group 2 transformers are over 30 years old.

	Age Group								
Type	0-10yrs	11-20yrs	21-30yrs	31-40yrs	41-50yrs	>50yrs	# Unknown	Total	%
Regulators	0	0	0	2	2	13	0	17	10.76%
Grounding Transformers	2	15	25	39	18	12	30	141	89.24%
Total	2	15	25	41	20	25	30	158	100.00%
%	1.27%	9.49%	15.82%	25.95%	12.66%	15.82%	18.99%	100.00%	

Table 7: Age Breakdowns of Group 2 Transformers

Group 3 - Station Service Transformers

Station service transformers and miscellaneous transformers form the third group of the transmission transformer asset class. Table 8 shows the age breakdown of these transformers. As seen from the table, not counting the number of unknown age, 54% of this group consists of transformers over 30 years old, however, a significant number of station service transformers do not have age data associated with them.

	Age Group								
MVA	0-10yrs	11-20yrs	21-30yrs	31-40yrs	41-50yrs	>50yrs	# Unknown	Total	%
Station Service	25	73	64	137	91	66	88	544	100.00%
Misc.	0	0	0	0	0	0	0	0	0.00%
Total	25	73	64	137	91	66	88	544	100.00%
%	4.60%	13.42%	11.76%	25.18%	16.73%	12.13%	16.18%	100.00%	

Table 8: Age Breakdowns of Group 3 Transformers

The above demographic data are displayed graphically and in more detail in Figure 26 to 29.

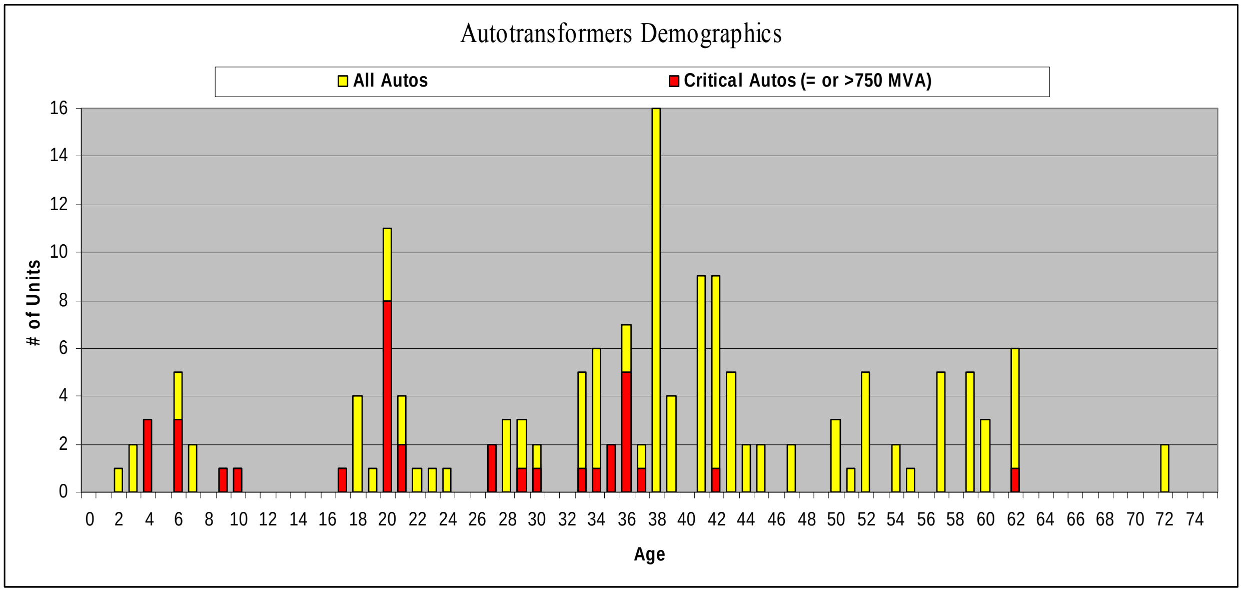

Figure 26: Autotransformer Demographics

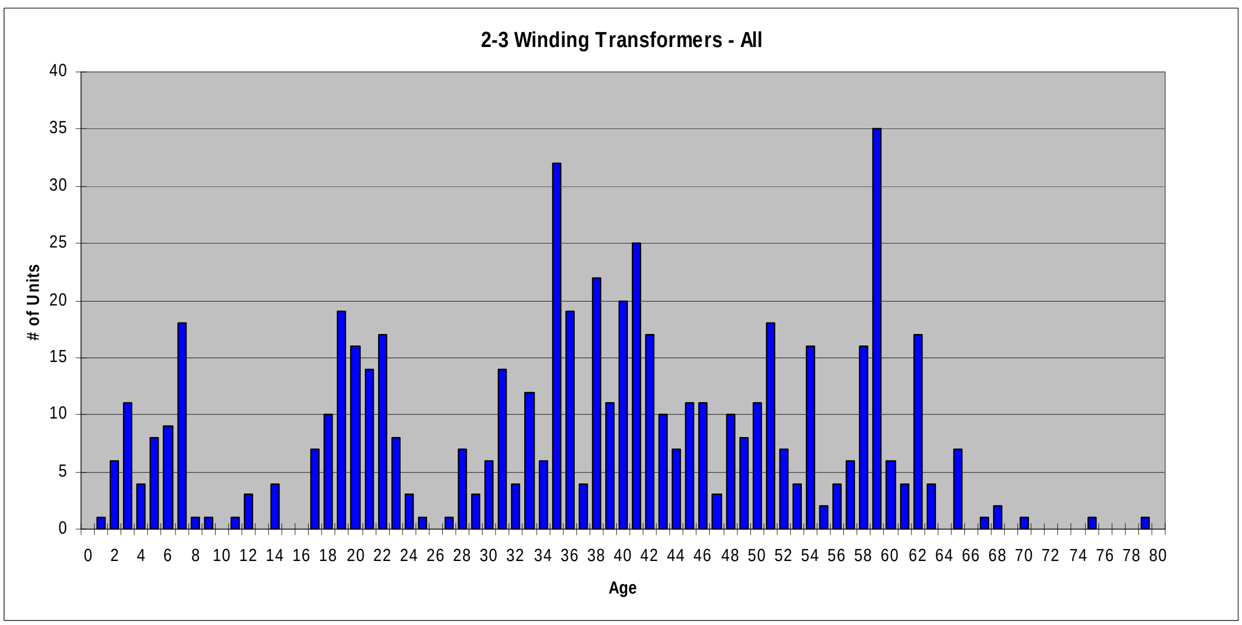

Figure 27: 2-3 Winding 115 and 230 kV Transformer Demographics

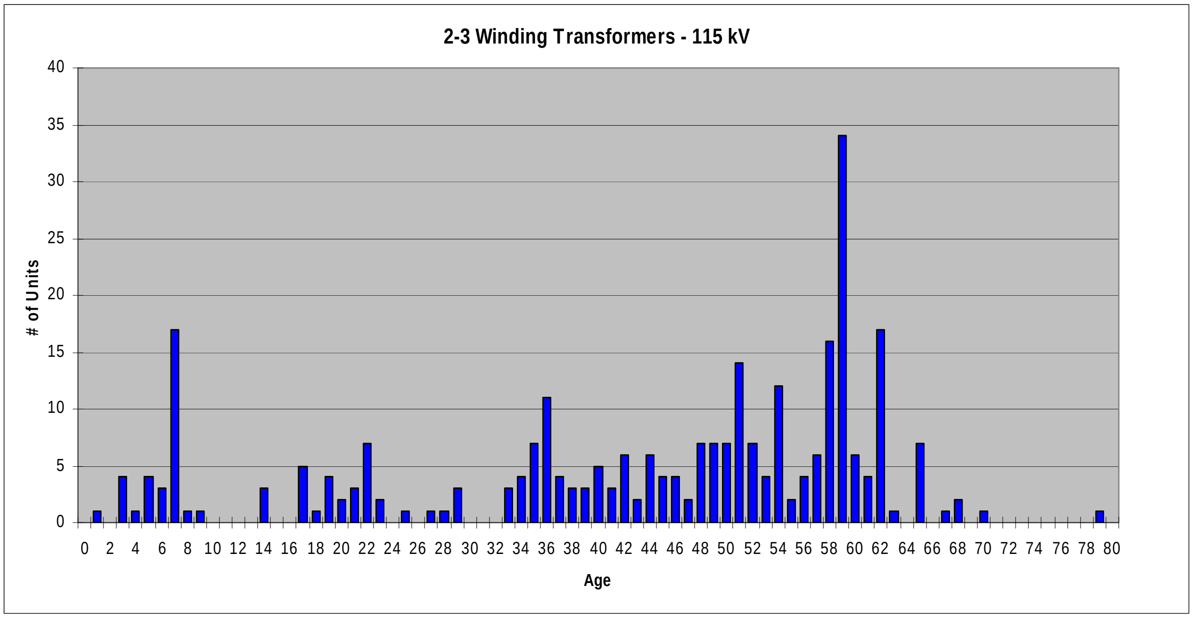

Figure 28: 2-3 Winding 115 and 230 kV Transformer Demographics

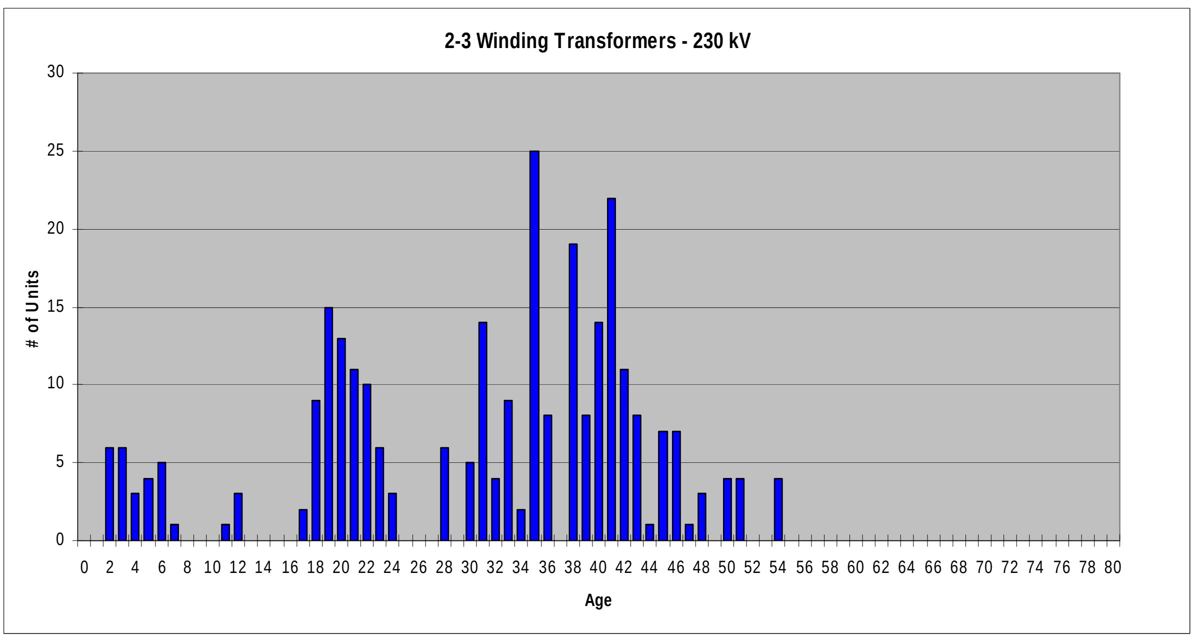

Figure 29: 2-3 Winding 230 kV Transformer Demographics

3.7 HV/LV SWITCH DEMOGRAPHICS

Hydro One currently manages 14,329 switches of different voltage classes and ages as shown in Table 9. About 55% of these are LV switches and the remaining 45% are HV switches. Approximately 29% of the switches are more than 40 years old. However, some caution has to be exercised in the interpretation of the data analysis because of the very poor demographic switch data in the Hydro One databases.

	LV			HV			Totals
	13.8 kV	27.6 kV	44 kV	115 kV	230 kV	500 kV	
Total	1564	3849	2316	2842	2985	773	14329
(%)	10.91%	26.86%	16.16%	19.83%	20.83%	5.39%	100.00%

Table 9: HV/LV Switch Demographics

3.8 High Voltage Instrument Transformers (HVITs) - Demographics

Hydro One currently manages 4297 HVITs. Table 10 shows the breakdown of all HVITs with respect to four nominal voltage classes. As can be seen from the table, HVITs are used throughout the transmission system, but the majority (approximately 59%) are used at 230 kV.

		Voltage Class					
		69 kV	115 kV	230 kV	500 kV	Total	(%)
Age Group	0-10yrs	0	246	592	31	869	20.22%
	11-20yrs	0	553	506	59	1118	26.02%
	21-30yrs	0	91	193	52	336	7.82%
	31-40yrs	0	112	546	78	736	17.13%
	>41yrs	0	159	178	3	340	7.91%
	Unknown	0	139	519	240	898	20.90%
	Total	0	1300	2534	463	4297	100.00%
	(%)	0.00%	30.25%	58.97%	10.77%	100.00%	

Table 10: HVIT Demographics (All Types)

Table 10 also illustrates the age demographics of HVITs. This table shows, about 29% of the total population is older than 30 years.

The HVITs are categorized into the following sub-categories based on insulation medium and type:

a) Oil filled Current Transformer (Oil CT)
b) Oil filled Capacitive Voltage Transformer (Oil CVT)
c) Oil filled Voltage (Voltage) Transformer (Oil VT)
d) SF_6 Insulated Current Transformer SF_6 CT)
e) Other or undefined

Table 11 shows the breakdown of HVIT Oil CTs with respect to three nominal voltage classes. This table shows that Oil CTs are used in Hydro One' transmission system at ≥ 115 kV and the majority of these (approximately 82%) are used at 230 kV.

		115 kV	230 kV	500 kV	Total	(%)
Age Group	0-10yrs	10	24	3	37	2.78%
	11-20yrs	3	257	6	266	20.02%
	21-30yrs	27	82	6	115	8.65%
	31-40yrs	4	389	5	398	29.95%
	>41yrs	12	65	0	77	5.79%
	Unknown	12	276	148	436	32.81%
	Total	68	1093	168	1329	100.00%
	(%)	5.12%	82.24%	12.64%	100.00%	

Table 11: HVIT, Oil CT Demographics

Table 12 shows the breakdown of HVIT Oil CVTs with respect to three nominal voltage classes. This table shows that Oil CVTs are used in Hydro One' transmission system at ≥ 115 kV and the majority of these (approximately 60%) are at 230 kV.

		115 kV	230 kV	500 kV	Total	(%)
Age Group	0-10yrs	219	500	25	744	35.33%
	11-20yrs	256	214	41	511	24.26%
	21-30yrs	9	74	42	125	5.94%
	31-40yrs	18	138	67	223	10.59%
	>41yrs	32	105	3	140	6.65%
	Unknown	80	232	51	363	17.24%
	Total	614	1263	229	2106	100.00%
	(%)	29.15%	59.97%	10.87%	100.00%	

Table 12: HVIT, Oil CVT Demographics

Table 13 shows the breakdown of HVIT Oil VTs with respect to four nominal voltage classes. This table shows that Oil VTs are used throughout the Hydro One' transmission system and the majority of these (approximately 67%) are used at 115 kV.

		69 kV	115 kV	230 kV	500 kV	Total	(%)
Age Group	0-10yrs	0	50	51	2	103	12.58%
	11-20yrs	0	304	26	0	330	40.29%
	21-30yrs	0	57	34	0	91	11.11%
	31-40yrs	0	100	5	0	105	12.82%
	>41yrs	1	117	8	0	126	15.38%
	Unknown	0	56	8	0	64	7.81%
	Total	1	684	132	2	819	100.00%
	(%)	0.12%	83.52%	16.12%	0.24%	100.00%	

Table 13: HVIT, Oil VT Demographics

Table 13 also illustrates the age demographics of Oil VTs. This table shows that about 4% of the total population are greater than 30 years old and that the age of approximately 43% of these is unknown.

Table 14 shows the breakdown of HVIT SF_6 CTs with respect to three nominal voltage classes. This table shows that SF_6 CTs are normally used at 230 kV and 500 kV.

		115 kV	230 kV	500 kV	Total	(%)
Age Group	0-10yrs	0	3	0	3	6.82%
	11-20yrs	0	9	2	11	25.00%
	21-30yrs	0	3	0	3	6.82%
	31-40yrs	0	14	0	14	31.82%
	>41yrs	0	0	0	0	0.00%
	Unknown	0	3	10	13	29.55%
	Total	0	32	12	44	100.00%
	(%)	0.00%	72.73%	27.27%	100.00%	

Table 14: HVIT, SF_6 CT Demographics

3.9 Station Insulators - Demographics

Combining the results of Hydro One surveys with known quantities of other apparatus which are supported by insulators, such as, switches, capacitor banks and reactors, it is possible to estimate insulator demographic data. The current population of Hydro One station insulators (stacks) is estimated to exceed 170,000, with over 90,000 being cap & pin, and over 78,000 being post type. In addition to these, there are also in excess of 48,000 strain insulator strings within stations. Approximately 99% of station insulators (strain, cap & pin, post) are porcelain, with the remaining 1% made of glass or a polymeric material. About 25% of strain and cap & pin insulators in the stations are 50 years of age or greater, and are considered to at the end of their design life.

As shown in Table 15 it can be seen that the total number of rigid insulators (Cap & Pin and Post) is about 170,000. Approximately 63% of these are installed on disconnect switches, about 2% support capacitors and other apparatus and with the remaining 35% being applied as bus supports.

Insulator Type	Total	< 50 Years	> 50 Years
Station Post	78134	60000	18134
Station Cap & Pin	91866	70866	21000
Station String	48000	35000	13000
Station Other	2000	1000	1000
Total	220000	166866	53134

Table 15: Estimated Number and Age of Station Insulators

3.10 Station Cables and Potheads - Demographics

Transformer secondary cable circuits constitute the largest segment of the cable population.

About 73% of these cables are of paper insulated lead covered (PILC) construction with the remaining 27% being cross-linked polyethylene (XLPE). About 4,500 potheads and terminators are applied on these transformer secondary cables. The total number of cables is estimated to be 2,256 and assuming an average length of each cable as 80 m, brings the total length of the cables to be approximately 180 km. Demographics data was available for approximately 72% of cables, providing a basis for a good age estimate of overall cable population.

Cables used to connect the static capacitor banks to the switchgear constitute the next largest segment of the cable population. These cables range in size from 350 kcmil to 3000 kcmil with the average being in the 1000 kcmil size range. It is estimated that there is over 25 km of single conductor cable used to connect the Hydro One capacitor banks to the associated switchgear. The number of associated potheads and terminators is estimated at about 1000. The remainder of the Hydro One cable population comprises of relatively small sized, 2/0 to 500 kcmil range, three conductor cables supplying station service and grounding transformers.

3.11 Capacitor Banks - Demographics

Hydro One currently manages 354 capacitors banks located in transmission stations. Table 16 shows the capacitors demographics with respect to three nominal voltage classes. As can be seen from the table, approximately 84% of capacitors are used at voltages under 50 kV.

		Voltage Class				
		< 50 kV	115 kV	230 kV	Total	(%)
Age Group	0-10 yrs	66	13	22	101	28.53%
	11-20 yrs	161	6	7	174	49.15%
	21-30 yrs	23	2	3	28	7.91%
	31-40 yrs	1	1	0	2	0.56%
	41-50 yrs	1	0	0	1	0.28%
	>50 yrs	0	0	0	0	0.00%
	Unknown	45	2	1	48	13.56%
	Total	297	24	33	354	100.00%
	(%)	83.90%	6.78%	9.32%	100.00%	

Table 16: Capacitor Demographics

3.12 HIGH PRESSURE AIR SYSTEM - DEMOGRAPHICS

Hydro One currently manages 25 HPA systems, including 79 compressors, 70 dryers, and 377 air receivers for HPA systems.

Table 17 shows the age demographics of compressors and dryers. As is shown, approximately 47% of the compressors and 38% of the dryers are over 30 years old. Interesting, only 3 compressors and 2 dryers were installed during the period of 11 to 20 years ago.

		Compressor	(%)	Dryer	(%)
Age Group	0-10yrs	2	2.53%	3	4.29%
	11-20yrs	6	7.59%	16	22.86%
	21-30yrs	3	3.80%	0	0.00%
	31-40yrs	29	36.71%	23	32.86%
	41-50yrs	15	18.99%	11	15.71%
	>50yrs	0	0.00%	0	0.00%
	unknown	24	30.38%	17	24.29%
	Total	79	100.00%	70	100.00%

Table 17: Compressor and Dryer Demographics

3.13 Batteries and Chargers - Demographics

Hydro One currently manages a total of 660 transmission station and communications (Telecom) batteries and a total of 672 battery chargers. As shown in Table 18 approximately 87% of the total transmission batteries and approximately 60% of the chargers were installed in the last twenty years.

		All Batteries		Chargers	
		Total	(%)	Total	(%)
Age Group	0-10 yrs	341	51.67%	232	34.52%
	11-20 yrs	233	35.30%	169	25.15%
	21-30 yrs	69	10.45%	96	14.29%
	31-40 yrs	2	0.30%	110	16.37%
	41-50 yrs	0	0.00%	27	4.02%
	>50 yrs	0	0.00%	0	0.00%
	Unknown	15	2.27%	38	5.65%
	Total	660	100.00%	672	100.00%

Table 18: Transmission Batteries and Chargers Demographics

3.14 Station Grounding Systems - Demographics

Hydro One Hydro One Inc (Hydro One) currently manages 281 transmission stations, all of which have their own grounding systems. Approximately 50% of the grounding systems were installed/upgraded in the last 50 years, while only 16% were installed/upgraded within the last 30 years, as shown in Table 19.

		Transmission Station Grounding Systems	(%)
Age Group	0-10yrs	12	4.27%
	11-20yrs	16	5.69%
	21-30yrs	17	6.05%
	31-40yrs	46	16.37%
	41-50yrs	50	17.79%
	>50yrs	134	47.69%
	Unknown	6	2.14%
	Total	281	100.00%

Table 19: Transmission Station Grounding System Demographics

3.15 AC/DC Station Service Equipment - Demographics

Hydro one currently manages AC and DC station service systems at each transmission station. Only limited demographic data is available on certain key components such as the station service transformers and transfer switches.

3.16 Station Buildings - Demographics

Table 20 shows the geographical breakdown of transmission station buildings. As is shown, approximately 74% of the total population are in the southern region of the Hydro One system.

		Number of Buildings				
		Northern	**Southern**	**Unknown**	**Total**	**(%)**
Building Type	Control Building	72	345	31	448	49.1
	Auxiliary Systems Buildings	32	112	0	144	15.8
	Occupied Buildings	40	123	0	163	17.9
	Ancillary Buildings	60	97	0	157	17.2
	Total	204	677	31	912	100.0
	(%)	22.4	74.2	3.4	100.0	

Table 20: Regional Breakdown of Transmission Buildings

4.0 Station Asset Performance

This section provides performance data for major power system assets that are found at Hydro One Stations excluding Protection and Control assets.

4.1 Circuit Breaker Performance

Hydro One keeps outage frequency and outage duration records for its HV circuit breakers. The trends for forced outage frequency are improving slightly based on the data over the period 2003-2009. However average forced outage frequency rates over the period remain higher than the CEA all-Canada average.

Figures 30, 31, 32 and 33 show the frequency of outages of Low Voltage, 115 kV, 230 kV and 500 kV breakers compared to the CEA all-Canada Average. In the figures (1) represents first half of year and (2) represents second half of year.

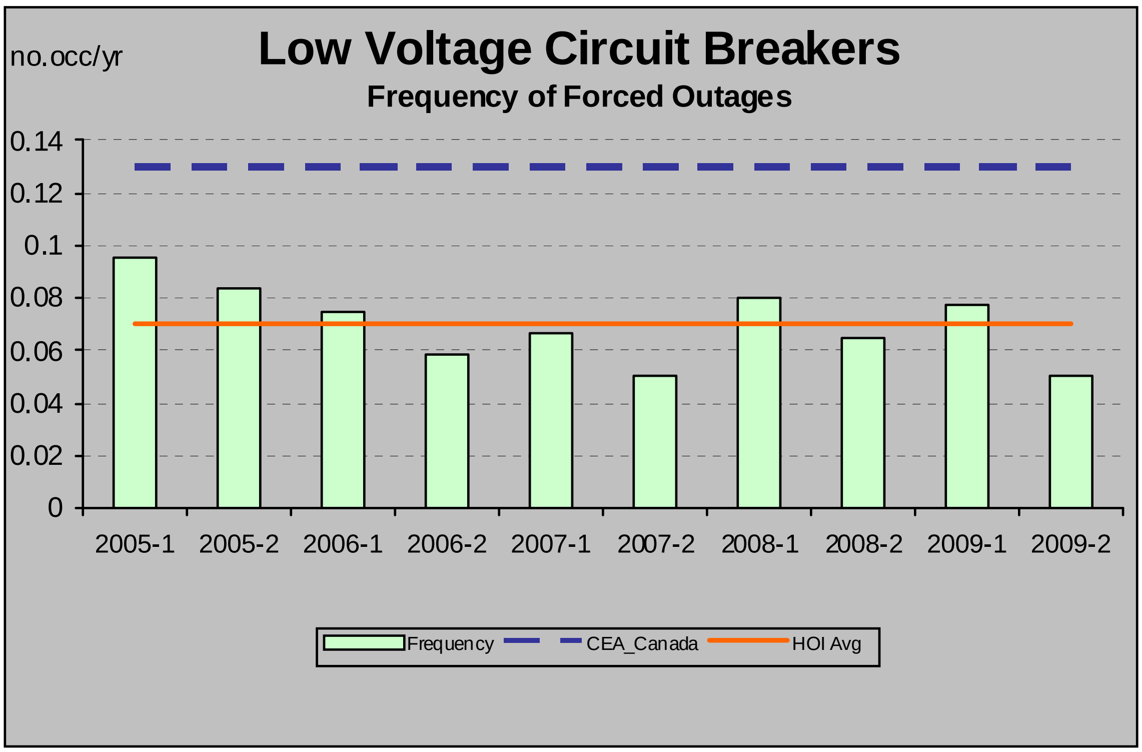

Figure 30: Frequency of Low Voltage Breaker Outages

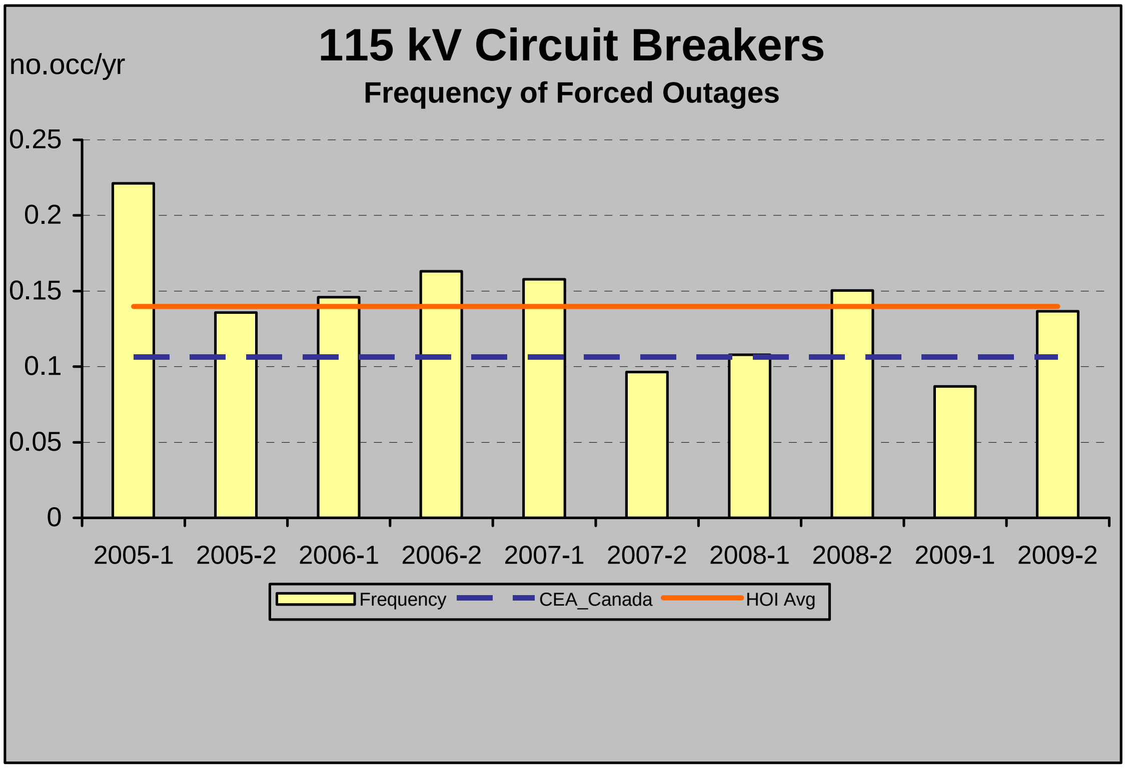

Figure 31: Frequency of 115 kV Breaker Outages

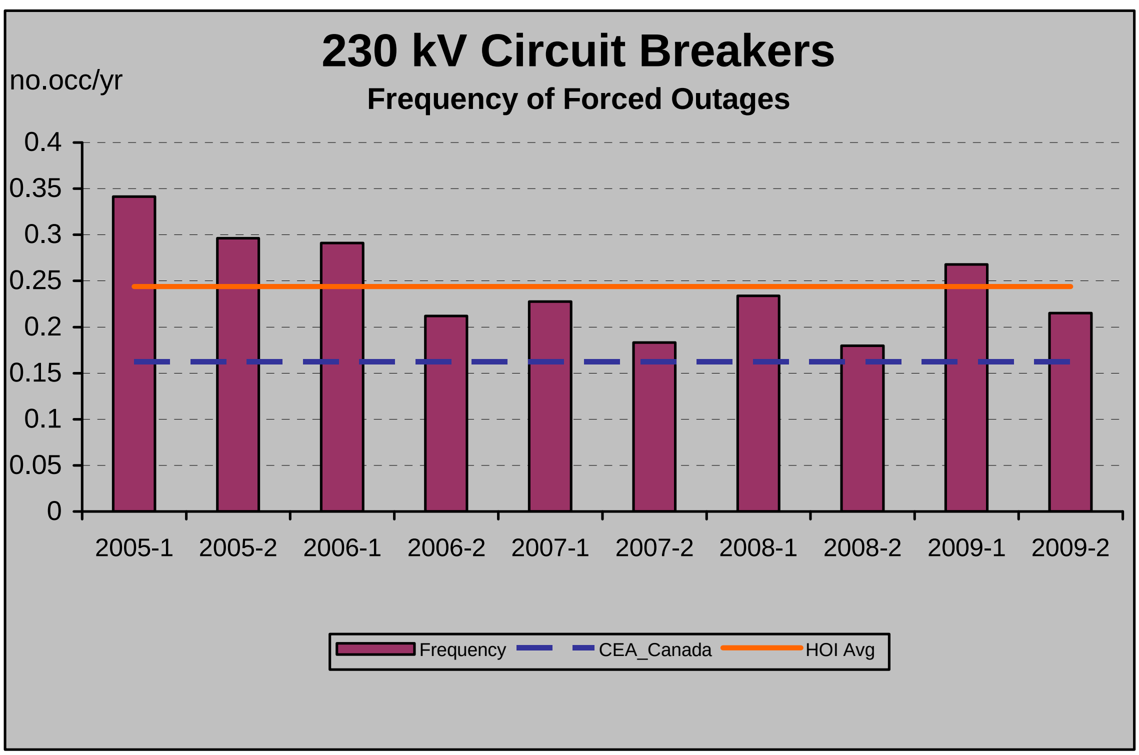

Figure 32: Frequency of 230 kV Breaker Outages

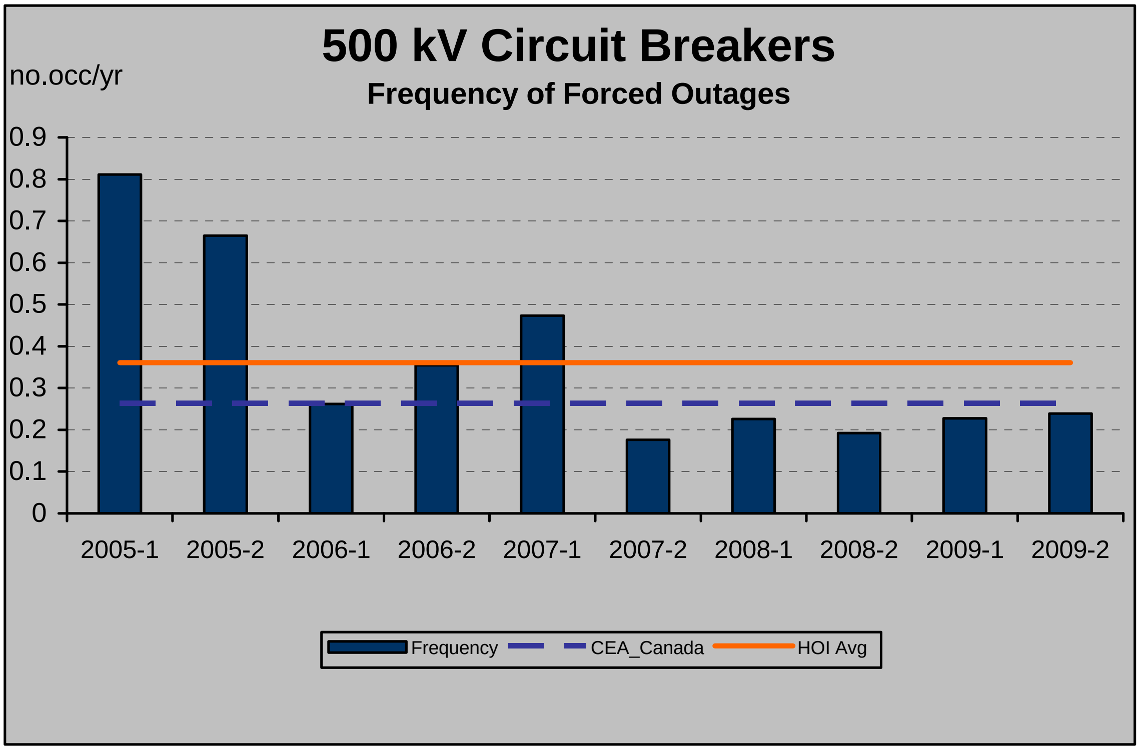

Figure 33: Frequency of 500 kV Voltage Breaker Outages

Figures 34 35, 36 and 37 show the unavailability Low Voltage, 115 kV, 230 kV and 500 kV breakers due to forced outages compared to the CEA all-Canada Average. In the figures (1) represents first half of year and (2) represents second half of year.

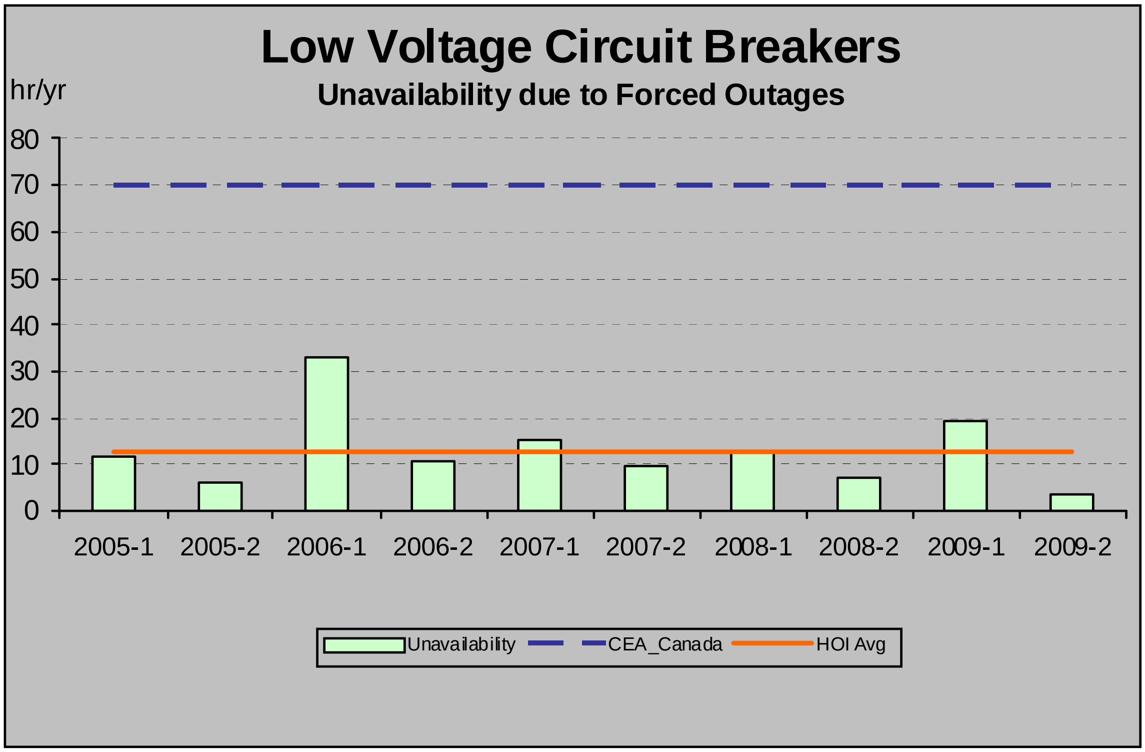

Figure 34: Unavailability of Low Voltage Breakers Due to Forced Outages

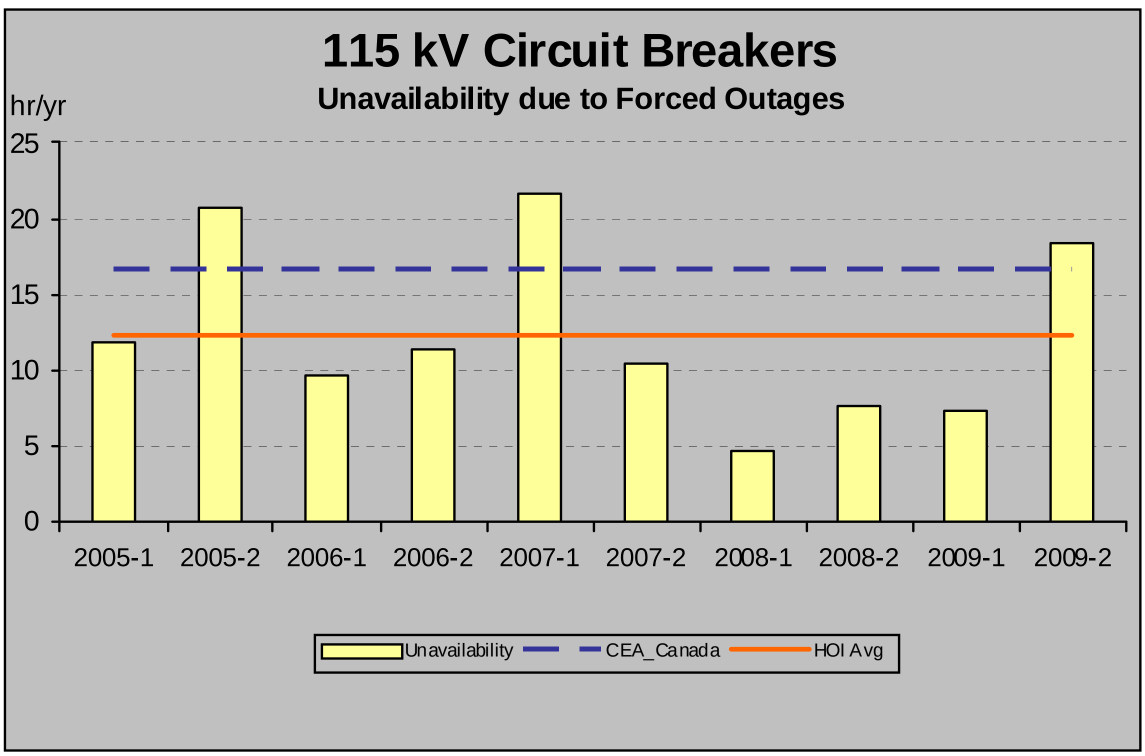

Figure 35: Unavailability of 115 kV Breakers Due to Forced Outages

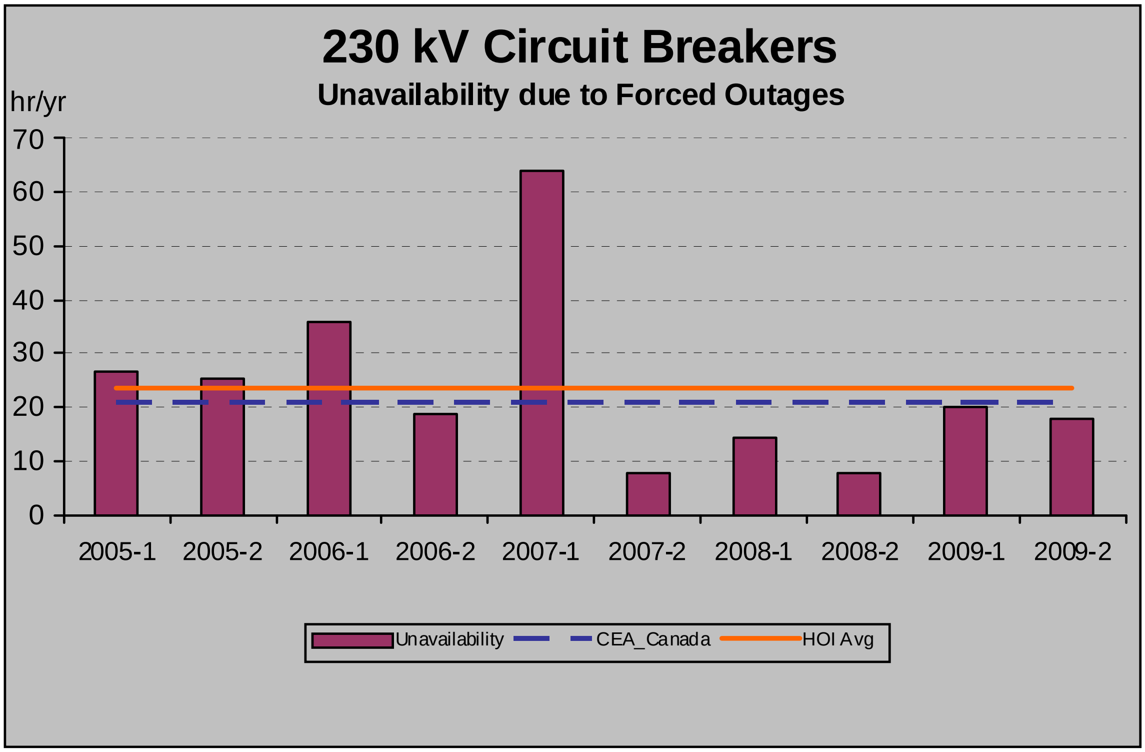

Figure 36: Unavailability of 230 kV Breakers Due to Forced Outages

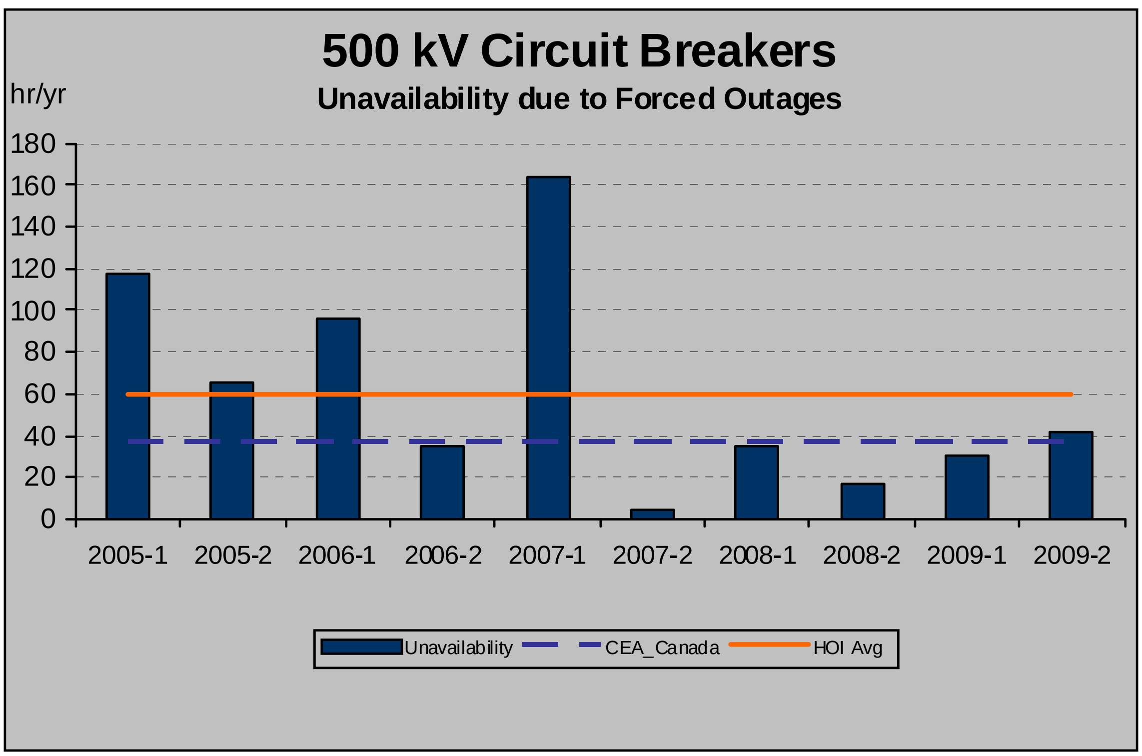

Figure 37: Unavailability of 500 kV Breakers Due to Forced Outages

4.1.1 Oil Circuit Breakers - Performance

Hydro One keeps outage frequency and outage duration records for its HV circuit oil breakers. The trends for forced outage frequency are improving slightly based on the data over the period 2003-2009. However average forced outage frequency rates over the period remain higher than the CEA all-Canada average. Nevertheless oil breakers remain the best performing class of breakers on the Hydro One system.

4.1.2 SF_6 Circuit Breaker - Performance

There is clear evidence from an increasing trend in forced outages and increasing maintenance costs, of deteriorating performance of the early vintage SF6 breakers over the last 5 years. These failure prone SF6 breakers represent less than 10% of the HV breaker population about 44% of the worst performing HV breakers (based on forced outage frequency) are SF6 CBs.

A large proportion (about 30%) of the SF6 breaker population is applied for the most onerous, special purpose duties, such as reactor and capacitor bank switching, some involving several hundred operations per year thus accelerating the mechanical and electrical wear out of the breaker. The complex control and operating mechanisms installed in almost all of these early vintage breakers resulted in increased operating problems and significant maintenance and refurbishment expenditures. Most of these very poor performing breakers have reached or surpassed their mechanical design life of 2000 switching operations.

Heaters are required on many of these breakers to prevent liquefaction of the SF6 gas at the low temperatures prevailing in Ontario. Heaters and control equipment, contactors, thermostats, and wiring degrade at an accelerated rate under these extreme conditions.

Gas seals leak at an increased level at low temperature putting increased pressure associated apparatus. Generally, earlier models have more problems than later ones, since modern equipment has improved seal and valve designs.

4.1.3 Air Blast Circuit Breakers - Performance

ABCBs are no longer manufactured, and as of 2010, are not supported with parts or technical expertise by two of the original three manufacturers. It is expected that the third vendor will cease technical support in the near future. Replacement parts, if they can be obtained are prohibitively expensive.

The utility industry has identified degradation of gaskets, seals, and valves as the critical long-term issues related to EOL of ABCBs. Experience has shown that gasket and seal deterioration is time-related with major performance problems being experienced when gaskets and seals are 20-25 years old. To deal with these in the past Hydro One has undertaken a major rebuild of each ABCB after approximately 20-25 years of service. The last rebuild program was completed in

1995. OEM facilities and resources associated with the rebuild program are no longer available and major rebuilds are no longer feasible.

There is clear evidence from forced outage data and increasing maintenance costs, of poor ABCB performance:

- The 5-year average forced outage frequency for Hydro One 230kV ABCBs is 0.39 occurrences per breaker per year.
- The 5-year average forced outage frequency for Hydro One 230kV ABCBs is 2.6 times the all-Canada average for 230 kV breakers.

4.1.4 Gas Insulated Switchgear (GIS) - Performance

Early GIS designs experienced many problems and failures. Over the past ten years many of the more failure prone designs have either been replaced or refurbished, however the transmission system still contains a significant number, representing about 60% of the total SF6 breaker population, of these early designs.

The initial high voltage GIS installations consisted typically of first generation European sourced components which in most cases were mechanically complex and relatively unproven for the operational duties encountered on the system, particularly at the then higher than standard operating voltages and short circuit interrupting requirements. As with all new developments, there was a relatively high early life failure rate, due primarily to prototype design problems and manufacturing /site assembly deficiencies. Failure rates and sustainment costs over the first five years of operation were in some cases five times higher than comparably rated, conventional air insulated substations. In addition, the complex hydraulic and other operating mechanisms installed in almost all of the 1970's and 1980's vintage GIS circuit breakers resulted in operating problems and significant sustainment expenditures.

Hydro One has now replaced one of the poorest performers, which was a double-pressure design manufactured in the mid 1970s and early 1980s and supplied by ITE (USA) who are no longer in business. Recent improvements in the single pressure design have resulted in relatively simple, low energy and more reliable operating mechanisms.

Apart from the circuit breakers, many of the other GIS components performed poorly; primarily disconnect switches solid epoxy cone insulators, SF6-air bushings and instrument transformers. GIS disconnect switches have turned out to be very critical components of a GIS, second only in importance to the circuit breakers. The purpose of the disconnect switch is to provide safe electrical isolation of associated circuit breakers, buses and line exits during maintenance activities as well as during normal service. Disconnect switches whether in AIS or GIS have very little rated interrupting capability because they are only opened off-load, i.e. the associated breaker is opened first. GIS disconnects operated reasonably well at 138 and 230 kV levels but performance at 500 kV was very poor. After many years of problems, a new standard and test procedure was developed in the early 1990s to eliminate this issue. For the more problematic 500 kV GIS disconnects placed in-service in the late 1980's, measures such as operating restrictions or field modification of contact geometry and shielding, have been employed to mitigate the risk of failures.

Metal enclosed, concentric, SF_6 insulated buses are used to interconnect other live GIS components such as circuit breakers, disconnect switches and interfaces with overhead lines, cables and transformers. Within the bus, aluminum conductors are supported on epoxy resin insulators. About 30% of the failures which have occurred since the late 1970s have been on these epoxy resin insulators. The current failure rate is considerably lower and Hydro One has developed diagnostics and monitoring procedures to detect potential failures. Figure 38 shows the number of 500 kV GIS failures over the last 30 years.

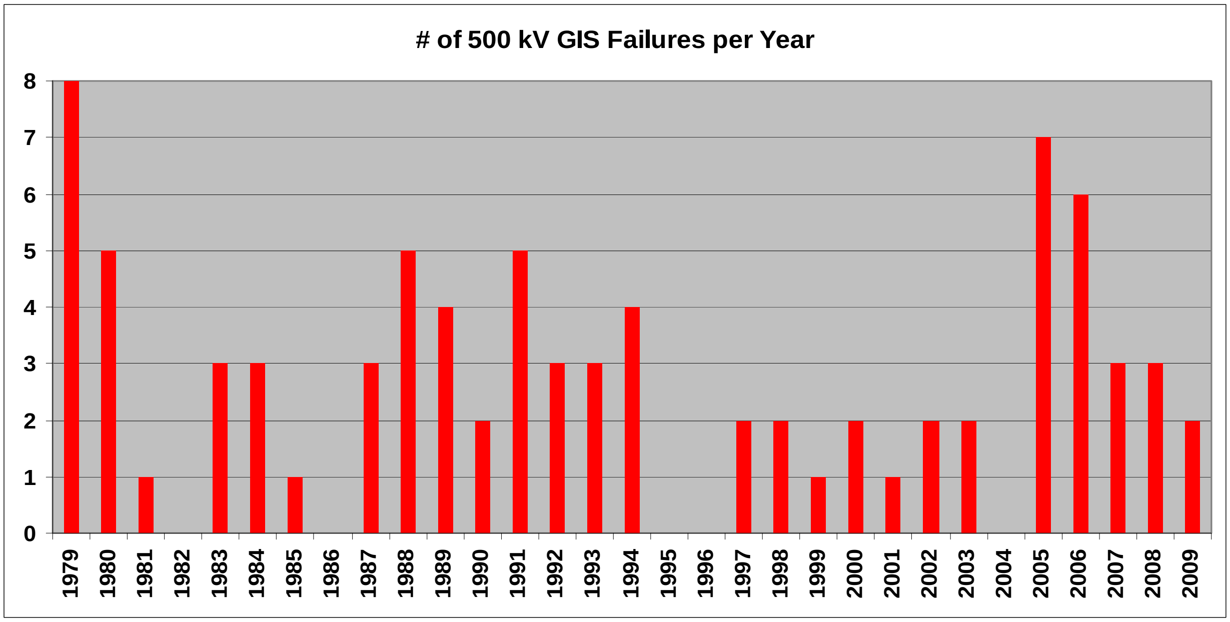

Figure 38: 500kV GIS failures per year

Failure rates and sustainment costs over the first five years of operation were in some cases several times higher than comparably rated, conventional air insulated substations. A combination of design improvements, field modifications and upgrades and more recently replacement by modern technology at one site has resulted in a significant improvement, bringing the failure rate more in line with conventional equipment.

The fact that failure rates increase as the voltage level increases has been borne out by many studies and by individual users experience, including that of Hydro One, over the past 30 or more years. The Hydro One population of 500 kV GIS has experienced a higher than expected number of major failures over its lifetime. The 550 kV GIS major failure rate, was extraordinarily high over the first five years of service and only dropped to about 12% in the early 1990's. As teething problems diminished and corrective action was taken on a number of inherent design defects, the failure frequency has tended towards the global average of about 3 – 5% for this voltage class. There has been only one major failure on the 550 kV GIS family installed in the 1992/3 period, indicating the efficacy of the design and quality improvements implemented in the late 1980s. The 500kV GIS population has been stable since 1994 and failure rates on average are comparable with the global average. Similarly 230kV failure rates are comparable with the global average

However, lingering problems persist at several sites, the most significant being the Merivale 230kV GIS which still retains failure prone outdoor ITE bus and line terminations having a high leakage rate to atmosphere.

4.1.5 Metalclad Switchgear - Performance

Major failure rates for Hydro One Inc. medium voltage conventional metalclad switchgear assemblies, comprising about 1200 cells are estimated to average about 0.0015 per cell-year over the past 10 years, translating to an average of 1.8 major failures per year. However there is no formal Hydro One process for recording the performance of low voltage circuit breakers (including metalclad switchgear)

4.2 Transformers - Performance:

Hydro One keeps outage frequency and outage duration records for its HV transformers.

Figures 39, 40 and 41 show the frequency of outages of 115 kV, 230 kV and 500 kV transformers compared to the CEA all-Canada Average. In the figures (1) represents first half of year and (2) represents second half of year.

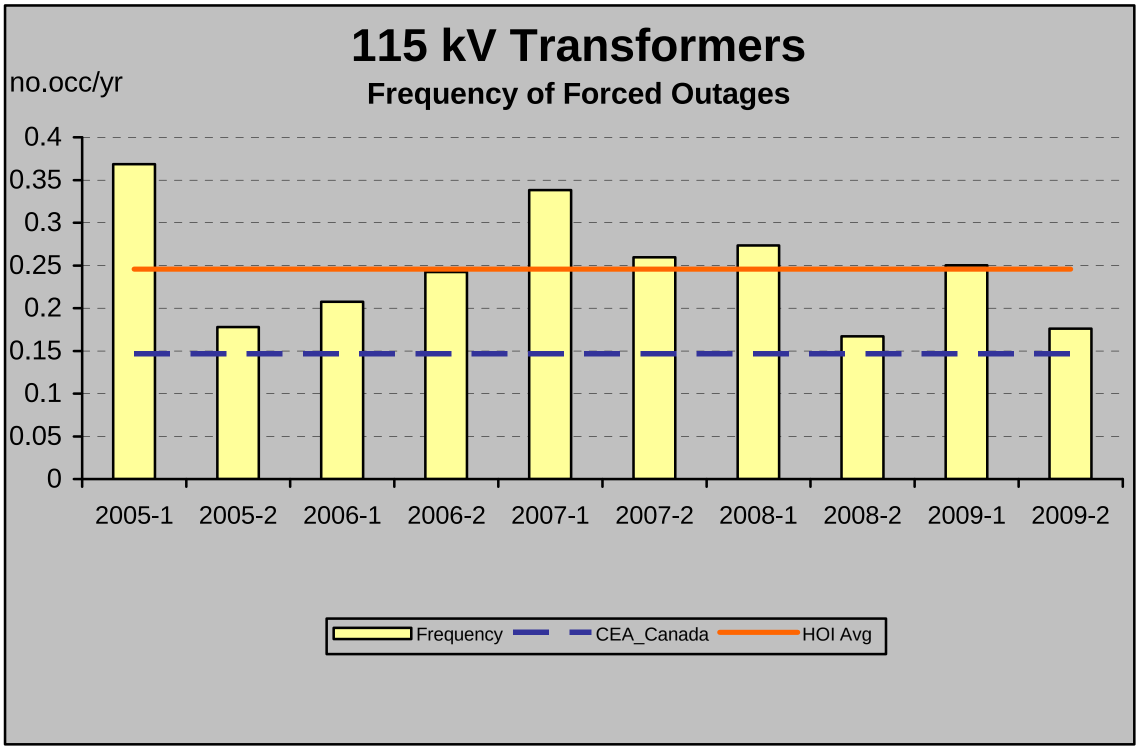

Figure 39: Frequency of 115 kV Voltage Transformer Outages

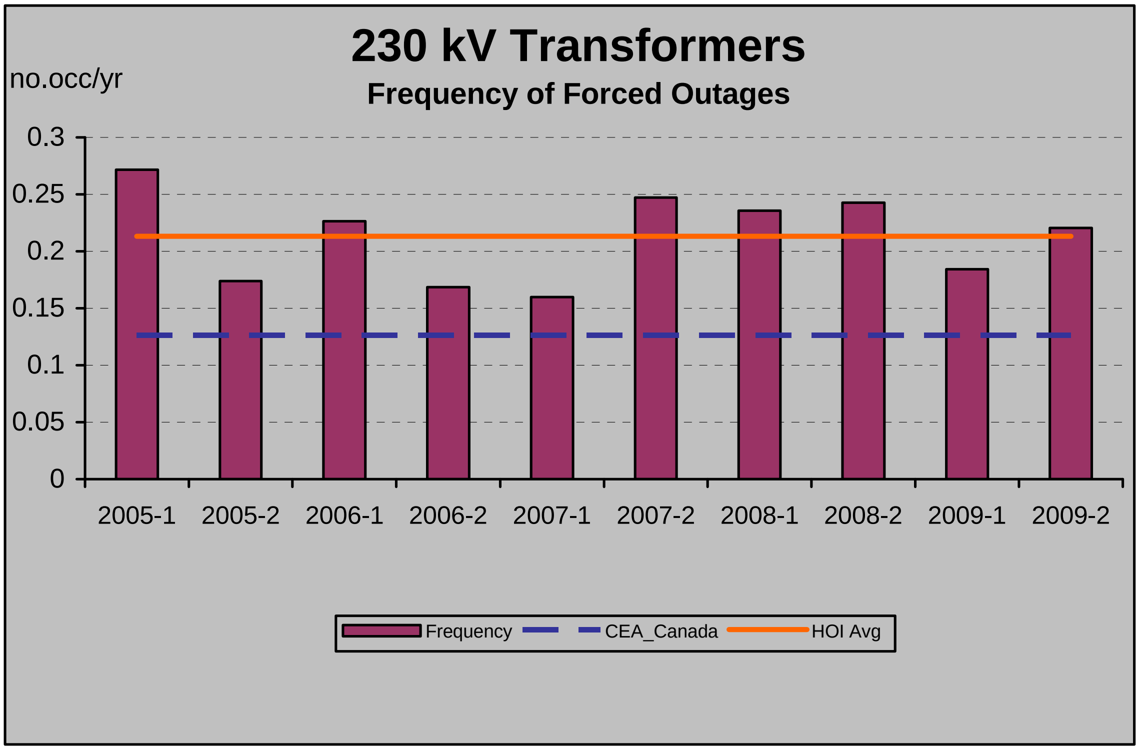

Figure 40: Frequency of 230 kV Voltage Transformer Outages

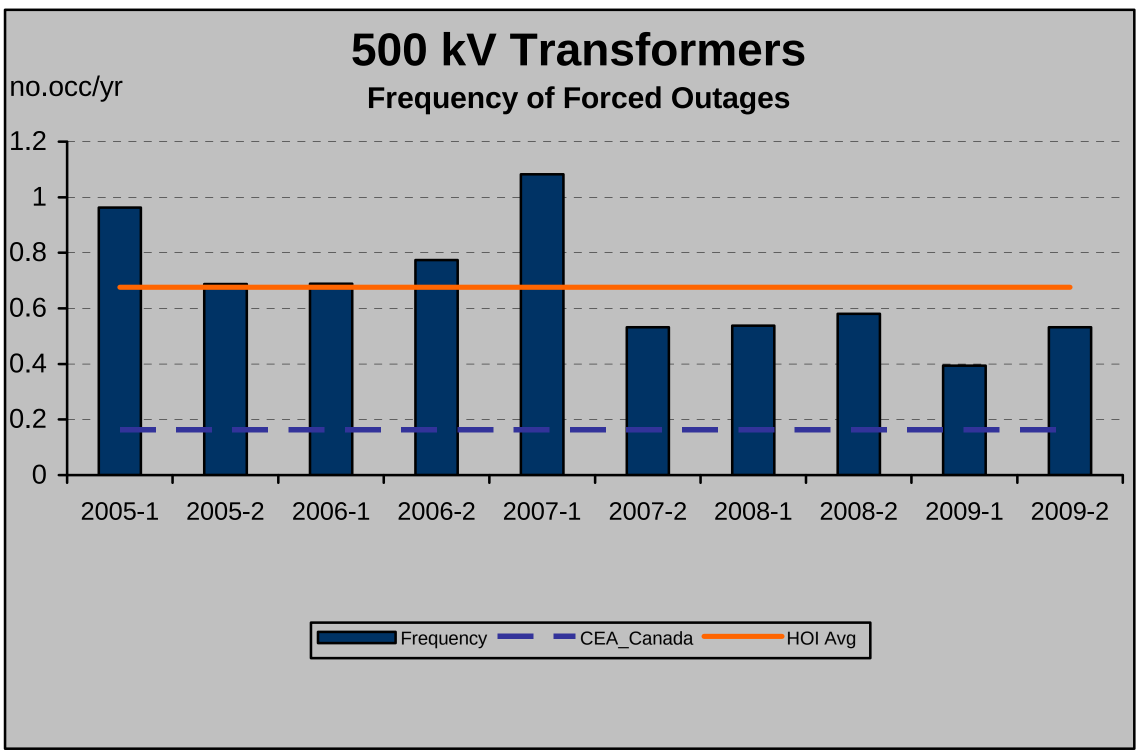

Figure 41: Frequency of 500 kV Voltage Transformer Outages

Figures 42, 43 and 44 show the unavailability Low Voltage, 115 kV, 230 kV and 500 kV transformers due to forced outages compared to the CEA all-Canada Average. In the figures (1) represents first half of year and (2) represents second half of year.

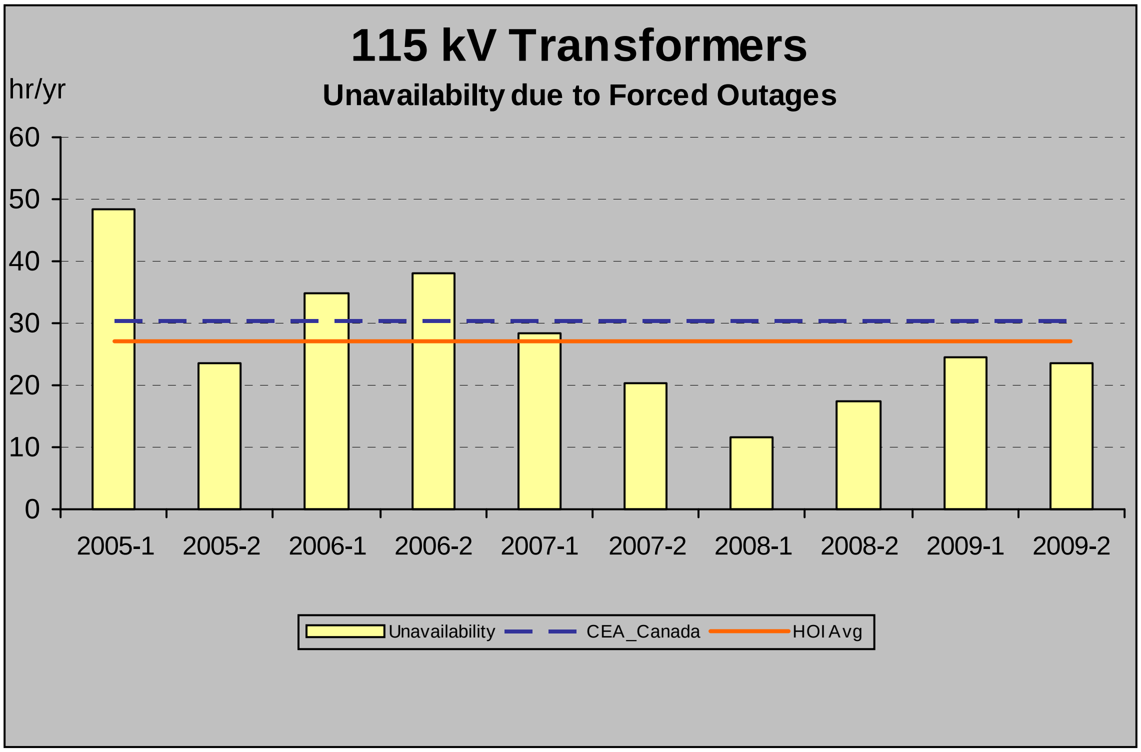

Figure 42: Unavailability of 115 kV Transformers Due to Forced Outages

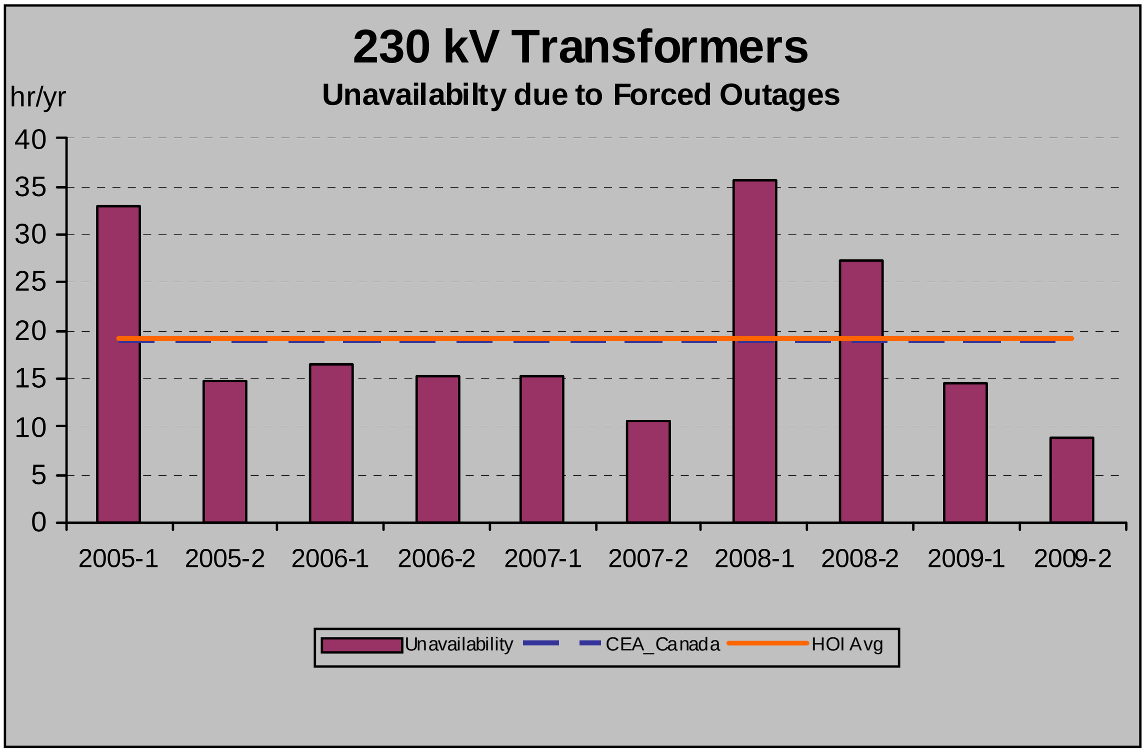

Figure 43: Unavailability of 230 kV Transformers Due to Forced Outages

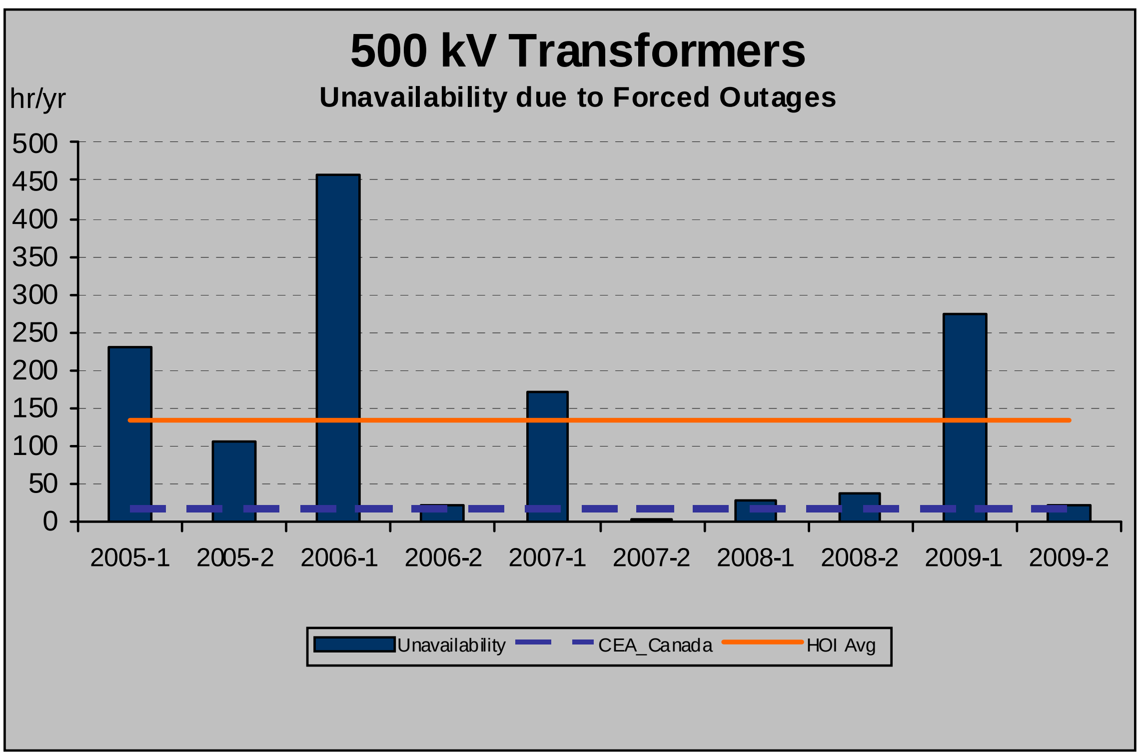

Figure 44: Unavailability of 500 kV Transformers Due to Forced Outages

All transformers performed worse than other CEA jurisdictions in frequency and 500 kV in unavailability. It is notable that H1N's 500 kV transformers performed many folds worse than both CEA All-Canada average performance measures.

4.3 HV/LV Switch - Performance

It is highly unusual for a disconnect switch to fail in the closed position. Switch deterioration is typically detected when a switch is called upon to operate to isolate or reconnect the device (circuit breaker, line, etc) with which it is associated. Hydro One typically experiences between 40 to 60 forced outages of other equipment per year as a result of switch defects. About 90% of switch defects do not result in an outage, because the switch can be immediately repaired or bypassed.

4.4 HVIT - Performance

Capacitive Voltage Transformers (CVTs) have some inherent design weaknesses, which relate to the high probability of resonant circuits being formed between the capacitive and inductive components of the VT. This propensity to resonance can be increased through interaction with external secondary circuits. CVTs comprise capacitors connected in series and are sensitive to overvoltages. Failure of one of the series units will impose higher than designed voltages on the remaining units leading to accelerated aging and destruction of the entire CVT. A voltage increase also exposes the connected metering and protection system to overvoltages which can result in equipment failure.

There are some significant differences between power transformers and oil filled instrument transformers with respect to degradation, failure and end-of-life. The design of instrument transformers is more complex and less conservative than with large power transformers. Consequently, the dielectric and thermal stresses on the insulation tend to be greater and degradation of the insulation can occur more rapidly. The overall result of this is that for HVITs reliability tends to be poorer and lifetime shorter than for large power transformers.

The most significant failure mode of instrument transformers is internal dielectric breakdown. These failure rates are higher than for power transformers and some patterns of failure related to specific types of equipment have emerged.

4.5 Station Insulators - Performance

Most of the data required for assessing the condition of insulators is being collected via maintenance activities. This is the most cost effective and practical method for collecting asset condition information. Hydro One has also carried out a detailed inventory and condition survey of its insulators at a cross-section (48 out of 281) substations in the province to provide a reliable and consistent basis for the ongoing management and replacement of insulators. A review of over 140 equipment trouble reports in 2003 indicated that 43% of the troubles were found during station inspection and 20% during routine maintenance for a total of 63% found during planned maintenance or inspections. Over 20% were found during routine switching of equipment in or out of service which imposed added safety risk to personnel. Only15% of the reports indicated that a safety problem was created by the failure.

Porcelain strain insulators within the station are usually in strings consisting of between 5 and 20 individual units. The insulator string can continue to be functional with a number of cracked units. End-of-life for a string of insulators is normally defined by a given number of cracked units.

4.6 Capacitor Bank - Performance

Capacitor banks are a composite asset consisting of capacitors, fuses, insulators and the support structure. Inrush current limiting reactors are also mounted on many of the Hydro One banks, especially for back-to-back configurations. As these are all essentially static devices, their maintenance requirements are minimal and are usually confined to visual inspection and other non-invasive checks such as infrared surveys.

External corrosion of the can at the bushing and other weldment locations are relatively common, even on the current designs of capacitors. This usually leads to leakage of the dielectric fluid and ultimately to can failure. In the recent past such failures have occurred on batches supplied by certain manufacturers, leading to accelerated EOL.

Internal degradation of fuses and capacitors can occur, primarily as a result of failure of seals and ingress of moisture. Detection of such degradation is normally carried out by visual inspection looking for signs of leakage and any abnormal heating effects. Internal degradation is also caused by operation at excessive steady state and transient voltages leading to dielectric failure. Transient overvoltages can be caused by the restriking of circuit breakers (e.g. bulk oil circuit breakers) still being used for the switching duty.

For insulators, internal degradation processes can occur, however, they are extremely difficult to detect. Assessment is normally limited to visual inspection to detect cracked insulators. The more reliable station post insulators have been applied on all capacitor banks for the past 20 or more years. The support structure will deteriorate primarily as a result of interaction with the environment due to corrosion. This can also be effectively assessed by visual inspection.

4.7 High Pressure Air - Performance

The quality of the air supplied by the HPA system is vital for the safe and effective operation of ABCBs. It is essential that contamination and moisture levels in the air be kept within very tight limits. If this is not the case serious deterioration and ultimately catastrophic failure of the circuit breaker may occur.

In most applications, air blast circuit breakers operate infrequently. In these cases the compressor is only called upon rarely for short bursts of activity to top up the stored air pressure. However, most of the compressor run time is not for breaker operation, but for making up air lost due to leaks. These leaks are usually associated with the breakers or with the isolating valves especially during long periods of cold weather or significant temperature swings. As with other mechanical devices with many moving parts, the degradation of a compressor is expected to be related to the number of hours of operation. Corrosion, wear and deterioration of internal components such as valves and seals are the most significant degradation processes. These can be addressed by regular inspections, minor overhauls and occasional major overhauls, if considered cost effective.

Another specific issue for HPA systems is that some components are classified as pressure vessels. In such cases they are subject to specific testing and regulation in accordance with pressure vessel legislation. The costs associated with fulfilling these requirements in a deteriorating system may give rise to an overall decision to replace the system.

Hydro One has well developed detailed maintenance procedures for HPA systems with a separate set of inspections and tests for the compressor, the dryer, air receivers, piping and condensate collection systems. Particular attention is paid to the quality of the air supplied, with frequent measurement (or on-line monitoring) of moisture levels. This process ensures the effective performance of the systems.

Those parts of the HPA systems which are covered by the Boilers and Pressure Vessels Act are subject to 3-year testing and approval in accordance with The Technical Standards and Safety Authority (TSSA) registration requirements.

4.8 Battery and Charger - Performance

Condition information for all batteries and chargers comes from maintenance activities. For batteries and chargers the maintenance cycle, depending on the activity is from 3 months to 5 years.

Effective battery life tends to be much shorter than many of the major components in a station. For traditional wet batteries, most electric utilities report a typical lifetime of 15 - 20 years and for the more modern sealed batteries, lifetimes are half of this.

The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

It is well understood in the utility industry that regular inspection and maintenance of batteries and battery chargers is necessary. In most cases the explicit reason for carrying out regular maintenance inspection is to detect minor defects and rectify them. However, critical examination of trends in maintenance records can give an early warning of potential failures.

Despite the regular and frequent maintenance and inspection of battery systems, failures in service occasionally occur.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. Batteries consist of multiple individual cells. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery.

Because batteries have relatively short lifetimes (<20 years), there is a need for continuous replacement. Utilizing information available from regular maintenance and inspection programs and responding to battery alarms results in a high overall reliability for batteries.

Battery chargers are also critical to the satisfactory performance of the whole battery system. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the batteries themselves (35-40 years). Nevertheless, problems do occur. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it is normal practice to replace the battery charger.

4.9 Station Grounding Systems - Performance

The condition of grounding connections above ground are routinely checked during routine maintenance and station inspections. Continuity tests or other tests on the grounding system are not routinely carried out to determine the grounding condition below grade.

Hydro One has a continuing program to evaluate the adequacy of station grounding facilities at all high risk stations. The criteria used to select these sites were age, fault levels, history of faults, phase arrangement, soil resistivity, station size, location(urban or rural) and re-development of adjacent properties.

To date more than 100 stations have been completed, at the rate of about 10 stations per year. These evaluations consist of soil resistivity measurements, full determination of the ground network, fall of potential measurements and application of a software based model to assess the potential rise, and step and touch potentials for a maximum fault level.

Almost all of the stations evaluated between 1999 and 2009 were found to be in need of some grounding improvements.

Approximately 25% of the grounding systems assessed was found to be in “Very Poor” condition and at a very high risk of failure. Major refurbishment of these was required as soon as possible to remove potential safety hazards. All safety related items of an urgent nature which are uncovered by the grounding evaluations are addressed and repaired immediately they are reported. Also, approximately 40% of the grounding systems assessed were found to be in either “Fair” or “Poor” condition and at a risk of failure requiring refurbishment within the next five years to remove potential safety hazards. The remainder of the evaluated grounding systems assessed was found to be in “Good” or “Very Good” condition

The below grade grounding evaluations generally found deficiencies in the implementation of present station grounding practices and in some stations deterioration of the surface stone barrier was identified. In general it was found that mesh, structure and fence tough potentials coordinated with safe body withstand potential for summer and winter conditions at the majority of the stations except for some specific fence locations within certain stations. Remediation of the crushed stone installation by replacement or removal of grass, clay, sand was required in some areas within many of the stations evaluated, in order to coordinate touch potentials with the safe body withstand potentials.

Serious below grade deficiencies, such as pedestal bus support structures in the switchyard found to be disconnected from the rest of the station grounding system, were discovered at several of the locations evaluated. Poor condition of the fence grounding was found at several of the stations.

The grounding problems identified above grade mainly deal with the need to keep the station facilities in line with present grounding practices and standards

4.10 AC/DC Station Service Equipment - Performance

Generally while the AC and DC station service systems must comply with regulatory requirements regarding performance and reliability they are treated as part of the station infrastructure and are inspected and functionally tested during routine station inspections, typically on a quarterly basis.

For critical stations the NPCC Criteria Document A-03 “Emergency Operation Criteria”, section 4.10.1 (System Restoration - Testing Requirements), details a number of tests that must be performed regularly at certain stations to ensure that facilities are available when required. Hydro One has identified a total of 70 stations that are on the list of key facilities needed to initiate restoration following a blackout (Basic Minimum Power System, BMPS).

Except for a few significant system events and problems related to a limited number of certain key components over the past 10 years performance of these systems has been generally acceptable. The most significant event was the July 20, 2002 Bruce “B” Switchyard incident that resulted in loss of total station DC supply caused by the automatic DC transfer scheme.

As with other infrastructure components, observation of significant damage or deterioration or any loss of functionality detected from inspection or as a result of alarms are addressed by appropriate remedial action. Consideration for more significant intervention, i.e. refurbishment or replacement of systems would normally only occur if the level of ongoing work was high or if a specific report indicated serious degradation or performance issues such as in the case of transfer switches for both the AC and DC systems.

In these cases a systematic condition assessment is carried out since the company became aware of widespread problems via the incident reporting, routine inspection and referral processes. Other than in these circumstances, end-of-life would normally be related to other activity in the substation, i.e. major development, renovation or replacement of major plant and equipment.

5.0 Protection System Asset Descriptions

This section provides descriptions of Protection and Control assets that are found at Hydro One Stations. Protection systems consist of either a single or multiple primary measuring relay units and a host of auxiliary devices that provide logic functions. Primary measuring relays are complex devices with predictable expected life spans. Auxiliary devices such as simple relays and timers are considerably more robust.

The major components in protection system are:

- Primary measuring relays - Electromechanical, Solid State, Digital
- Auxiliary devices - Simple relays, Timers, Logic Controllers
- Panels or Racks - 19 inch rack, Steel panel, Ebony asbestos
- Mounting hardware - Primary relay cases, Auxiliary relay cases

5.1 Protection Relays

Protective relays and their associated systems are devices connected throughout the transmission system for the purpose of sensing abnormal conditions. They detect and isolate in conjunction with circuit breakers any abnormal conditions resulting from natural events, physical accidents, equipment failure or mal-operation due to human error. Protective relays and their associated protection systems are therefore indispensable for the safe and healthy operation of the transmission network.

The maximum time allowed for power system protection to correctly sense and isolate faulted equipment whether a transmission line, power transformer etc. is measured in a fraction of a second. High-speed isolation is necessary to protect and mitigate damage to expensive system equipment, reduce the health and safety risks to public/personnel and to maintain power system security/reliability.

Both failure to operate and incorrect operation can result in major power system upsets involving increased equipment damage, increased personnel hazards and possible long interruption of service. These stringent requirements with high potential consequences make it imperative that protection systems be extremely reliable. Protective devices come in three forms or technologies described as follows.

Electromechanical: Utilizes the principles of electromagnetic induction to convert electrical energy to mechanical movement to provide fault detection. An example of this type is shown in Figure 45.

Figure 45: Electromechanical Relay Panel

Solid State: Transistor and integrated circuit technology provide the means of fault detection. An example of this type is shown in Figure 46.

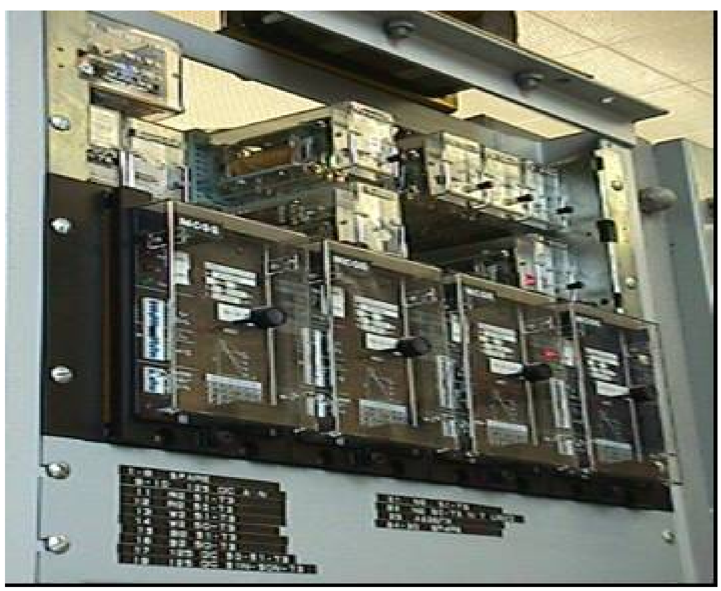

Figure 46: Solid State Relay Panel

Digital: The latest microprocessor based technology provides advanced fault detection capability. An example of this type is shown in Figure 47.

Figure 47: Digital Primary Schweitzer Relays

Protection relays may be either rack mounted, or located in the instrument compartment of switchgear. Older style electromechanical primary measuring relays are also mounted in cases specifically made for them that then mount on panels or racks.

5.2 Auxiliary Devices

Auxiliary devices include relays and timers that are usually mounted in auxiliary cases that in turn are mounted on panels or racks.

Three broad categories of auxiliary devices exist.

Type 1: Auxiliary relays and timers manufactured by ASEA used in their modern combliflex method of case mounting known as RX. This type is shown in Figure 48.

Figure 48: ASEA RX Type Auxiliary Relays

Type 2: Auxiliary relays and timers manufactured by ASEA used in their original method of case mounting known as RR. This type is shown in Figure 49.

Figure 49: ASEA RR Type Auxiliary Relays

Type 3: Auxiliary relays and timers directly panel mounted which include, Westinghouse, General Electric and English Electric type.

The vast majority of these auxiliary devices are either RX or RR.

5.3 Panels or Racks

Protection systems are assembled with the various components such as primary measuring relays, auxiliary devices, terminations and isolation devices mounted on panels or racks. Panels may be 24 inch painted steel, or ebony asbestos. Racks are 19 inches free standing painted steel. A typical installation is shown in Figure 50.

Figure 50: 24 Inch Steel-Type Panels with Protection, Auxiliary Relays, Flexitest Switches and Current Links

5.4 Mounting Hardware

Auxiliary devices such as relays and timers are usually mounted in auxiliary cases that in turn are mounted on panels or racks. Older style electromechanical primary measuring relays are also mounted in cases specifically made for them that then mount on panels or racks.

5.5 Control System: Remote Terminal Units (RTUs)

RTUs are located at all transformer stations to allow operating control from a centralized master control centre where the operators are located. The RTU provides status indication, alarm and control of all equipment located at the local station. The RTU transmits telemetry quantities such as Watts, VArs, Amps and Voltages used for indicating metering. The RTU may also perform certain control functions such as voltage regulation and breaker synchro-check depending on the station operating requirements.

Most RTUs are microprocessor or PC based and self-diagnosing. Microprocessor based RTUs may be single or dual-redundant depending on the reliability required in each installation. Dual redundant RTUs are also multi-ported to support communications to other electronic devices including Human-Machine Interfaces (HMI) used for local station control. Redundancy is provided in the processors only, since the input and output RTU architectures may be concentrated or distributed depending on the economies related to space constraints and cabling. The PC based installations will have a shorter life cycle and lower reliability than the microprocessor based devices as they have electromechanical data storage mechanisms and a relatively short obsolescence cycle. In some cases, the RTU function is performed as part of a distributed system, or integrated as a secondary function into another P&C system.

Distributed systems consist of networked stand-alone microprocessor-based IEDs that are dedicated to the control metering and annunciation function. In some cases, a protection IED provides a subset of the RTU data as a secondary function as shown in Figure 51.

Figure 51: GE D25 Distributed RTU Installation - 1999

Most RTUs are not subject to regular maintenance intervals and are only serviced upon failure. The new generation of RTU uses non-volatile memory that must be secured in order to operate reliably. The non-volatile memory (NVRAM) will have a life expectancy as short as eight years, and, in some cases, as long as the service life of the equipment. Devices with NVRAM with a service life that is less than the RTU will be scheduled for preventative maintenance to ensure that failures do not occur.

5.6 Protection System Monitoring

Protection system monitoring devices, including annunciators, digital fault recorders (DFRs) and sequence of events recorders (SERs) are widely deployed in transmission stations to provide detailed information on protection operation. The annunciators currently in use are ***solid-state*** electronic devices and the DFRs and SERs are microprocessor and PC based. The capability and sophistication of these devices has been rapidly developing over the past 15 years. As a result of this rapid development, issues of obsolescence, functionality, spare parts and support, particularly related to compatibility with modern IT and communication systems, are the main end-of-life factors. Condition is not normally a significant issue.

Fibre Optics

In the 1990s many electric utilities installed fibre optic links using either a wrap around on the overhead groundwire of their transmission lines, an underslung self-supporting cable or fibres integral with the overhead groundwire. In some cases these were comprehensive systems linking all the main sites in the company, in others it was limited to a few experimental links. There were some initial problems related to the installation processes causing damage to the fibres and some difficulties with splices, but subsequently we believe that the systems have proved reliable and effective.

Metallic Cables (Pilot Cables)

These are used to provide telecommunication channels for protection and control purposes. Based on UK and North American company experience, these are subject to periodic insulation resistance tests and continuity checks. These measures enable degradation to be detected and monitored, with unacceptable levels stipulated in the maintenance manuals. In many cases metallic cables are self-monitored, any indication that they are outside specified limits would trigger an alarm.

Site Entrance Protection Systems

This category consists of equipment required to protect metallic telecommunication cables (Hydro One and those of the telephone companies) that enter high voltage transmission facilities. The predominant equipment type is the neutralizing transformer; other types include isolating transformers and optical isolators. The most important functions performed by this equipment are safety of people and sustaining the operation of teleprotection systems during power system faults.

Teleprotection Tone Equipment

This equipment is a system utilizing telecommunication systems (usually owned by telecommunication companies) to send blocking or tripping signals to remote locations for protection purposes. The equipment owned by the electric utility is typically limited to the 'send and receive' multi-channel electronic devices in the transmission stations. The system is quite widely used as an alternative to metallic (pilot) wires.

Timing tests are carried out during commissioning and on watchdog monitors once the system has been commissioned. Some utilities carry out regular 'timing' tests to check the performance and functionality of the system. As with other electronic equipment these are repaired or replaced when failures occur. As they are multi-channel devices there is often some built in redundancy allowing flexibility in managing failures.

6.0 Protection and Control - Demographics

This section provides demographic data for Protection and Control assets that are found at Hydro One Stations.

There are approximately 10,300 relay systems in Hydro One, which are made up of approximately 70,000 individual relays. Technology changes over the years have lead to the adoption of three basic classes of relays. Prior to the emergence of solid state electronics relays used analogue electromechanical mechanisms. While this technology is relatively dated these relays have performed well for many decades and are still amongst the most reliable. With the emergence of solid state electronics in the sixties and seventies electronic/digital were adopted to meet the increasing demands of the power system and the need for more complex protections following the blackouts of 1965. More recently computerized relays are increasingly being used to replace aged and failed relays. Figure 52 shows the distribution in ages of all types of relays. Clearly substantial portions of the population have service lives well in excess of what might be expected of electronic or electromechanical devices.

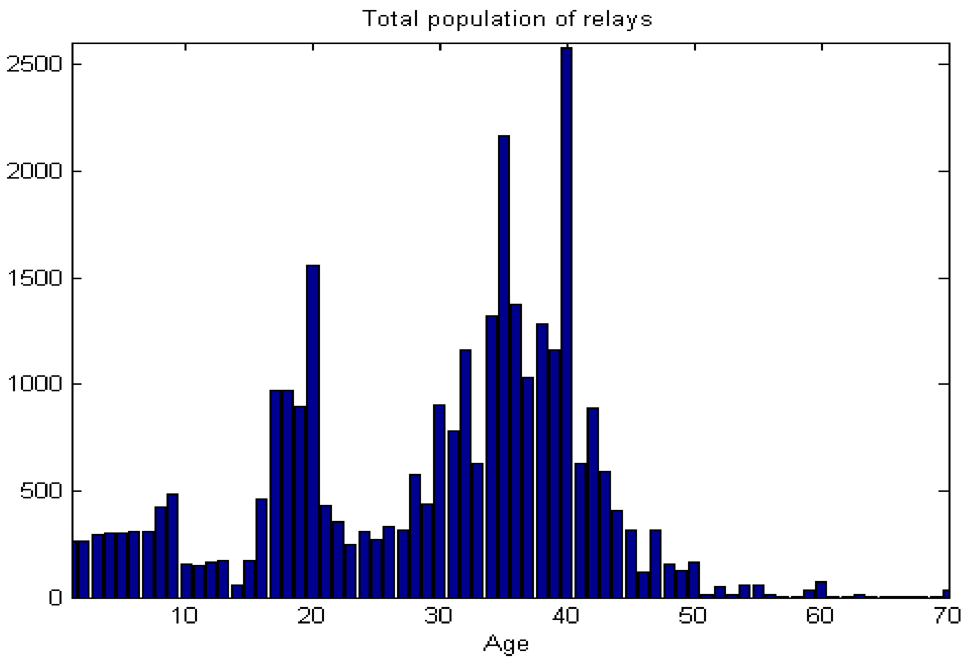

Figure 52: Total population of individual relays

The demographics of the Hydro One's protection systems broken down by voltage classes are shown in Table 21 below. Approximately 24% of these are more than 30 years old.

		Voltage Class					
		<50kV	115kV	230kV	500kV	Total	(%)
Age Group	0-10yrs	1005	516	515	76	2112	21%
	11-20yrs	942	325	517	165	1949	19%
	21-30yrs	1347	885	1304	224	3760	37%
	31-40yrs	745	626	631	11	2013	20%
	41-50yrs	111	166	35	0	312	3%
	>50yrs	49	98	0	0	147	1%
	Total	4199	2616	3002	476	**10293**	100%
	(%)	41%	25%	29%	5%	100%	

Table 21: Protection Profile

The total count of 519 RTUs is comprised of various generations of electronic devices. Approximately 45% of these are less than 5 years old as shown in Table 22.

Remote Terminal Units		Total	(%)
Age Classes	0-5yrs	232	45%
	6-10yrs	159	31%
	11-15yrs	93	18%
	>15yrs	35	7%
	Total	519	100%
	(%)	100%	

Table 22: Control Systems Profile

7.0 Protection and Control Asset Performance

With adverse demographic data as discussed above performance data, not unexpectedly, are showing signs of problems in the P&C category. For example Figures 53 and 54 show the causes of 230 kV transformer outages and 230 kV circuit breaker outages. The focus here is on the proportion of failure causes attributed to protection failures and to control failures. While these data are a small sample, they illustrate how relay and control system failures can have significant impacts on other critical assets and underline the importance of developing plans to maintain and improve performance in the face of the demographic problem.

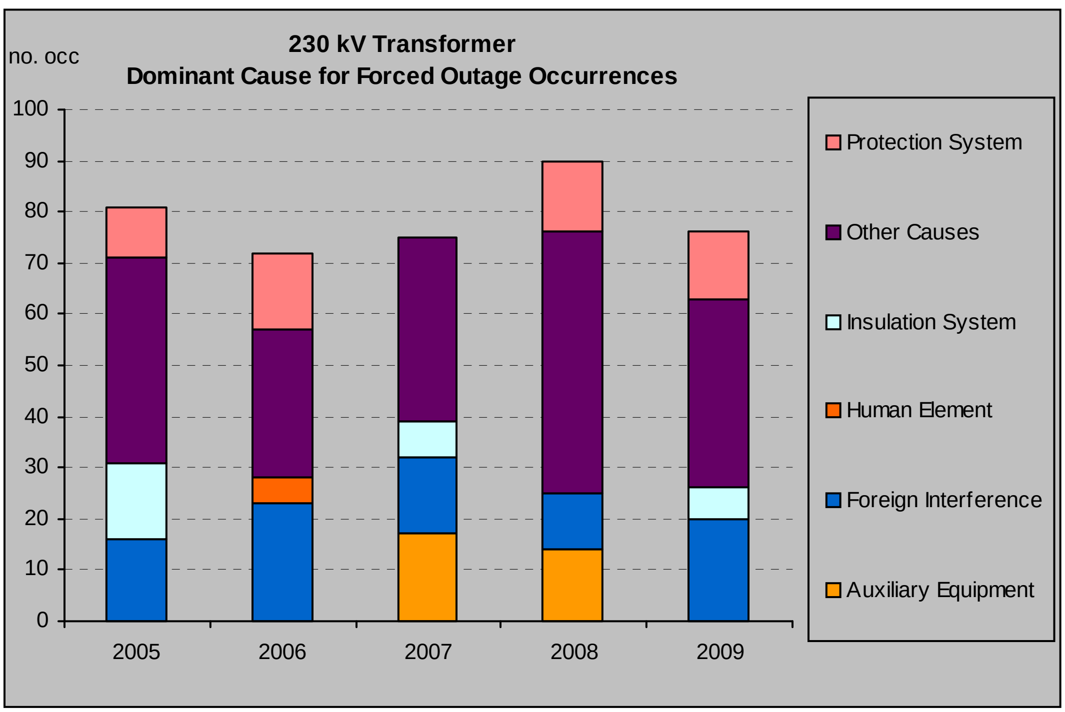

Figure 53: 230 kV Transformer Forced Outages

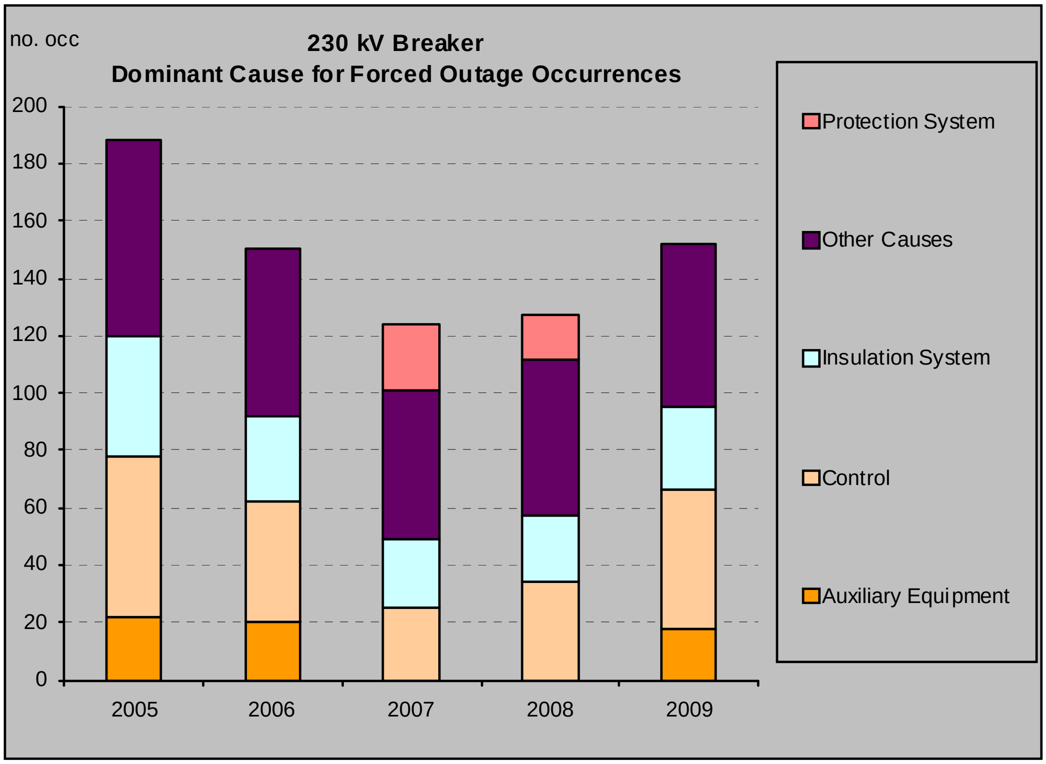

Figure 54: 230 kV Breaker Forced Outages

8.0 Lines Asset Descriptions

This section provides descriptions of Overhead and Underground Transmission assets that are found at Hydro One Stations.

8.1 Overhead Transmission Lines

The primary elements of overhead transmission lines include conductors, supporting structures, insulators, shieldwire hardware and the rights-of-way upon which they are constructed. The bulk of Hydro One's overhead lines are constructed using aluminum conductors reinforced with a steel core. The conductors are supported by steel structures, porcelain insulators and connecting hardware. The lines are protected from lightning strikes by shield wires mounted above the conductors.

Conductors

Transmission line conductors carry electrical energy from generating stations to transformation stations where the transmission voltage is lowered and the energy is redistributed to customers through distribution line conductors, generally of smaller capacity than the transmission conductors. Normally three conductors (one for each phase) constitute a single circuit, with an operating voltage on the circuit that results in phase-to-phase voltages between the conductors.

Figure 55 shows the Aluminum conductor, steel reinforced (ACSR) in a cut view. ACSR is the most prominent type of conductor used on transmission systems.

Figure 55: ACSR Conductor

In ACSR conductor the steel core strands supply the majority of the conductor's strength, which enables it to withstand the forces applied from wind, snow and ice as well as its own weight. The steel strands have both tensile and ductile properties so that they are able to withstand longitudinal forces and bending movements respectively, without failure. Individual aluminum strands of wire are laid over the core of galvanized steel wires, with a pitch length that is dependent on the diameter of the core over which it is arranged. Subsequent additional layers of aluminum wire strands are then applied with a reverse pitch, alternating with each additional layer.

The alternating pitch of the aluminum layers create a design that has some capability to reduce movement of the conductor as a result of the friction between the layers of aluminum strands. Some conductors are constructed with flat segmented aluminum strands that result in a smaller diameter for the same cross-sectional area and, as an added bonus, also increases the frictional surface areas between layers of the strands thus improving resistance to conductor swing and vibration. This design also has a reduced tendency for radio and television interference, as the corona discharges are less on a smooth round outer conductor surface.

The determination of the number of steel wires in the core is dependent on the strength of conductor required whereas the number of layers of aluminum is dependent on the amount of current the conductor is designed to carry.

Conductor sizes used in the transmission system range in diameter from 1.43 cm (just over half an inch) to 4.069 cm (just over one and a half inches).

The conductors are supported from structures at intervals (175 metres to 325 metres depending on operating voltage and height of supporting structures) and at tensions up to 222 kN that result in the conductor being elevated a minimum safe distance above the ground at its lowest point between structures at its design operating temperature, with a safety factor.

Conductors are arranged on the supporting structures with sufficient clearance from the structures, ground, overhead shieldwire and other phase conductors to prevent the operating voltage from flashing over between the various elements. The spacing arrangement also takes into account the ability of conductors to gallop (move in an up and down and/or sideways motion) during icing and wind conditions. Insulators with adequate strength to support the physical loads that will be encountered during anticipated weather conditions support the conductors. Between the supporting structures (spans) the insulating medium is air and this insulating quality is taken into account in the separation of the conductors along the route of the circuit.

As load current passes through the conductor the resistance of the conductor causes its temperature to rise. The change in temperature is proportional to the square of the load current passing through it. This rise in temperature causes the conductor to lengthen and to sag between the points of support, thus reducing the height of the conductor above ground. This factor can easily result in a reduction of clearances from ground in the order of 3 metres or more depending on the temperature increase of the conductor, the ambient temperature, wind and solar conditions and the distance between points of support. It is critical, therefore, to limit the amount of load carried by each transmission circuit to a level that is within its design capability.

The energy transported on the conductors consists of electrons that have a tendency to travel through the outer layers of the current carrying aluminum strands (skin effect). This results in the inner layers of the aluminum strands not being utilized to their full extent. To overcome this phenomenon the 500 kV system, a design is used where each phase consists of two or more individual conductors of smaller diameter that are held close to each other (approximately 45 cm apart) by means of mechanical connectors. Not only is this type of construction more efficient, it has better (reduced) corona performance and an ability to reduce the amount of conductor movement during wind and ice conditions.

The design most commonly used by Hydro One in the above situations is where four individual conductors form one phase conductor and are held apart in the shape of a 45 cm square which is shown in Figure 56. The surface area available for the current (energy) to flow in this design is now much greater than in a single conductor of equivalent size and thus the efficiency in transporting energy is enhanced.

Figure 56: Four conductor bundle with spacer

Shieldwires

Shield wires are either smaller ACSR conductors or galvanized steel stranded conductors mounted above the phase conductors and solidly connected to ground through the tower steel or ground conductor. Their function is not to carry load current but rather to shield the current carrying conductor from lightning strokes and safety dissipate the energy to ground.

8.2 Supporting Structures

A transmission line represents a mechanical system made of components such as conductors, ground wires, supporting structures (including wood poles, steel towers, and steel poles) with foundations, insulators, hardware and fittings. These transmission lines transport electrical energy from the generating facilities to transformation stations, large industrial customers and to municipal electric utilities.

The wood poles are harvested from various species of trees grown naturally in many parts of Canada. The tree species in use include Western Red Cedar, Jack Pine and Georgian Yellow Pine. These different species of trees have different strength and performance characteristics that are considered in the overall design of a transmission line. The mechanical and structural designs of overhead transmission lines are based on safety, reliability and security requirements. Wood has been a popular material for use in building transmission lines because of its cost effectiveness and reliability over the life of the asset, i.e. low capital and maintenance costs and ease of construction. Wood is a renewable resource and Canada has traditionally had a large supply of suitable trees for this purpose.

Wood poles are graded according to strength by class numbers (i.e. Class 1, 2, 3,...), where the smaller the number, the stronger the pole. Transmission wood pole lines are usually constructed with Class 2 or stronger poles to meet the design loading requirements of the transmission line.

Wood poles and cross-arms are normally treated with preservatives (e.g. creosote, pentachlorophenol or most recently, chromated copper arsenate) in order to prevent premature decay and extend their useful lives.

Wood structures also have a copper or aluminum wire installed across the cross-arm and down the length of the pole to connect all metallic materials and hardware to a metallic ground rod. This arrangement conducts any stray leakage currents to ground to prevent a wood pole or cross-arm fire.

The two basic transmission wood pole design types in use by Hydro One are “H Frame” design and “Single Pole” design. These are used for all tangent (in line) and small angle applications. For larger angles and dead-ending, a 3-pole semi-strain or dead-end structure design is used.

- H-Frame Structures (Figure 57) consist of two poles and a cross-arm. In some cases there are guy wires attached to the poles near the cross-arm and then attached to ground anchors located at 90 degrees from the direction of the line. Other means of reinforcing such structures incorporate cross-braces installed in an X configuration between the vertical poles. Due to the design of such structures they require more materials, occupy more right-of-way and are stronger than single pole structures.

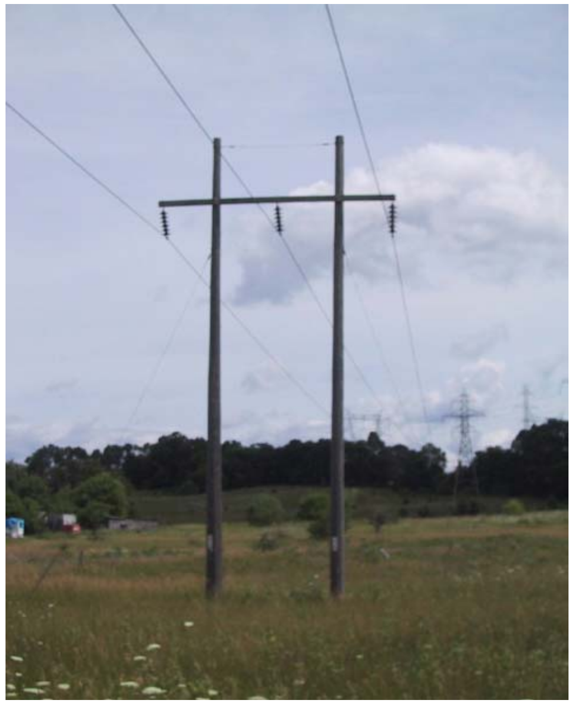

Figure 57: Transmission Line H–Frame Structure

- The "Single Pole" design uses a single pole of suitable height, in the range of 17 to 30 metres. Conductors are then suspended using steel arms with suspension insulators (Figure 58); the older "wishbone" design using two cross-arms attached at different points on the pole and slanted to provide spacing for the attachment of the three phase conductors they support (Figure 58; or standoff insulators (Figure 59). These structures are less expensive due to the use of less material, are not as strong and occupy less right of way than the H-frame structures.

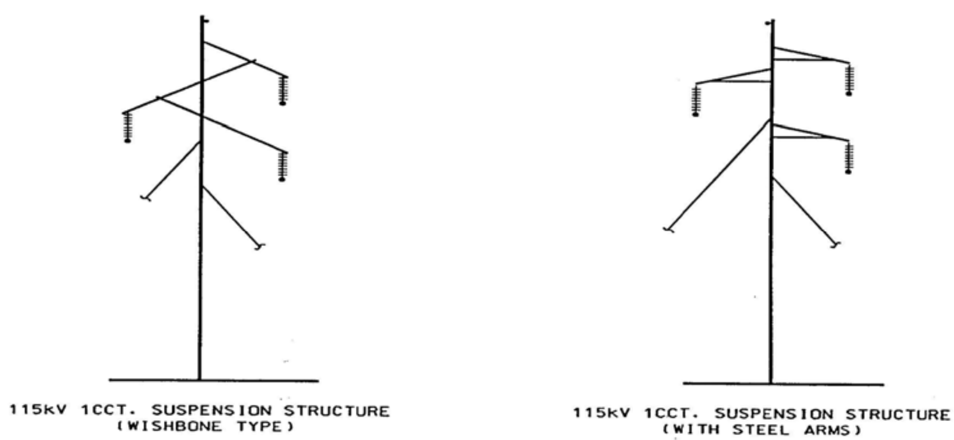

Figure 58: Single Pole Designs, "Wishbone" and "Steel Arms"

Figure 59: Single Pole Design, "Standoff"

8.3 Rights-of-Way

An overhead transmission line right-of-way (Tx-ROW) is a continuous, urban or rural land corridor with an established legal right for Hydro One to construct, operate, and maintain electrical utility transmission lines. The primary function of these corridors is for the transmission of electrical energy in a safe and reliable manner. The Tx-ROW asset provides the land base for building and/or installing structures and stringing conductors at a variety of voltage levels with appropriate access for operating and maintaining those facilities.

The Tx-ROW corridor is required as part of the transmission system whereby conductors at voltage levels of 115 kV, 230 kV and 500 kV are used to transmit electrical energy to customers from the various generation and supply sources throughout its service territory. Engineering and Design standards and the type of supporting structures determine Tx-ROW corridor width requirements. Conductors energized at voltage levels of 115 kV, 230 kV, and 500 kV require Tx-ROW widths averaging 30 m, 46 m and 64 m respectively. Tx-ROW corridors may contain one or more circuits. These circuits may form a single or multi-circuit line and they may or may not be at the same voltage levels. Multi-circuit line corridors vary in width and may require Tx-ROW clearing as wide as 220 m.

All new high voltage transmission line projects are required to go through an Environmental Assessment and approval process. This is to ensure that the potential social and economic impact of transmission line facilities and corridors have been addressed and have been dealt with in a satisfactory manner. The steps of the Environmental Assessment and approval process ensures that the selection of a preferred route for the new transmission line is determined after considering all environmental, cultural, social and economic impacts. This process may also rely on public hearings to assess alternative routes and to determine the final preferred route. The outcome of this process is an Order in Council (OIC) from the government that gives Hydro One the rights to acquire property and/or easements for the purpose of constructing the transmission line facilities. The OIC gives Hydro One the right to clear property of woody vegetation; to acquire and construct access; to erect or install overhead and underground conductors.

The OIC also gives Hydro One the authority to operate and maintain the equipment and the Tx-ROW within prescribed guidelines. Operation and maintenance of the transmission line includes the requirement to maintain clearances between vegetation and the transmission facilities and the rights of access.

Hydro One’s Tx-ROW properties occupy Crown Lands, (through License of Occupation), patent lands, (through easement rights), First Nation Lands (through easements), and lands owned outright by Hydro One.

All agreements governing Tx-ROW must have rights to conduct vegetation maintenance activities on the Tx-ROW and the right to manage trees on adjacent lands that pose a threat of falling into the line or growing into the minimum allowable side clearances thereby interfering with the safe operation and reliability of the line. Where vegetation has been allowed to encroach on the originally constructed width of the Tx-ROW, re-establishing the Tx-ROW to design width is an important aspect to the successful and safe operation of the transmission system.

Managers of vegetation programs are dealing with a biological system that is constantly changing. If a Tx-ROW is not maintained, in short time, through natural succession, it will revert back to the original forest cover.

Tx-ROW in Rural Areas

Tx-ROW in rural areas traverse both long narrow paths (single transmission lines with one or two circuits on one line) and wider Tx-ROW and shorter distances (multiple transmission lines on one corridor). However, some of the multi line corridors traverse long paths such as the lines between Otto Holden to North Bay to Sudbury to Missisauga.

The Tx-ROW system touches on many of the geological landforms found in Ontario as well as all forest regions ranging from deciduous to boreal to tundra. Local topography associated with any one Tx-ROW can range from low to high relief, from poorly drained bogs to well drained eskers, and from bedrock ridges to sand flats. Extreme topography, rivers, streams, wetlands, lakes and lack of road development can restrict Tx-ROW access. The adjacent land uses can also vary widely from rural residential developments, agriculture, managed woodlots, orchards, and mining to remote wilderness.

On Tx-ROW in rural areas, additional management constraints can apply in response to land owners when dealing with Tx-ROW located on First Nations lands, Federal lands, railway lands, Provincial lands and patented lands. The change in vegetation species mix through each of the Forest Regions in the Province results in different maintenance cycle requirements and a need for a variety of methods and tools for managing vegetation.

Tx-ROW in Urban Areas

Hydro One has transferred all its urban transmission corridors to Provincial ownership but still remains responsible for their maintenance. These urban corridors have essentially become grassed open areas, designated green belt and industrial or commercial lands. Urban corridors support a wide range of vegetation ecosystems associated with stream valleys, steep slopes, naturalized areas, maintained grasslands, un-maintained grasslands, scrub lands, recreational/park lands and industrial lands. Urban corridor land uses range from leases to cover commercial parking lots, transportation and industrial uses to agriculture, golf courses and landscaping nurseries to areas of "quiet enjoyment" and green belts. All urban Tx-ROW must be managed to the conditions and standards of the community within the bounds of local municipal bylaws and approvals. These owned properties total approximately 9,300 hectares in large population centres such as Metro Toronto and Greater Toronto Area, Ottawa, and Niagara Falls and 10,900 hectares in smaller population centres.

However, the high cost of lands in urban areas also provide an opportunity for compatible secondary land uses that generate revenue and, when successfully pursued, also reduces the total land area requiring maintenance expenditures by Hydro One. These factors lead to a different strategy for conducting ground maintenance and vegetation control on urban Tx-ROW, than rural Tx-ROW.

8.4 Underground Cables

Transmission underground cables are typically extensions to, or links between, portions of the Networks' overhead transmission system operating at 115 kV and 230 kV. There are no underground cables in the 500 kV system. Underground cables are mainly used in urban areas where it is either impossible, or extremely difficult to build overhead transmission lines due to legal, environmental and safety reasons.

The initial capital cost of a transmission underground cable circuit is about 10 times higher than the cost of an overhead transmission line of equivalent capacity and voltage. Transmission underground cables are also more costly to maintain/repair than an overhead transmission line and they pose environmental risks not present with overhead transmission lines as some are filled with pressurized insulating/cooling liquids.

Depending on the cable design the three phase conductors may be contained together within a steel pipe or each phase conductor is self-contained in its own sheath and installed separately underground. Transmission underground cables are systems, similar to transmission lines, made up of numerous components, all of which need to integrate and function properly in order to deliver the electric power with the reliability that is demanded.

There are several different types of high voltage underground cables in use on the Networks' transmission system:

- Low-Pressure Liquid-Filled (LPLF) Cables
- High-Pressure Liquid-Filled Pipe-Type (HPLF) Cables
- Extruded Cross Linked Polyethylene (XLPE) Cables:

Low-Pressure Liquid-Filled (LPLF) Cables

This design features a hollow core conductor to carry insulating liquids, which saturates and maintains the dielectric strength of the lapped paper insulating layers over the cable core. The cable is mechanically protected by an aluminium or lead shield, which in turn is protected from corrosion by an insulating polyethylene or rubber jacket.

The cable system is maintained continuously under positive liquid pressure from liquid reservoir tanks, either gravity fed or pressurized tanks situated at the terminal ends, and occasionally along the cable route. In unusual situations, due the cable route, elevations and length, a low pressure pumping plant may be used.

This type of cable is almost invariably installed as three individual phases in a horizontal configuration with a separation of 15-20 cm directly in an excavated trench or in a concrete encased duct bank. The trench is backfilled with material that retains moisture and conducts heat away from the cables.

An example of this type of cable is shown in Figure 60.

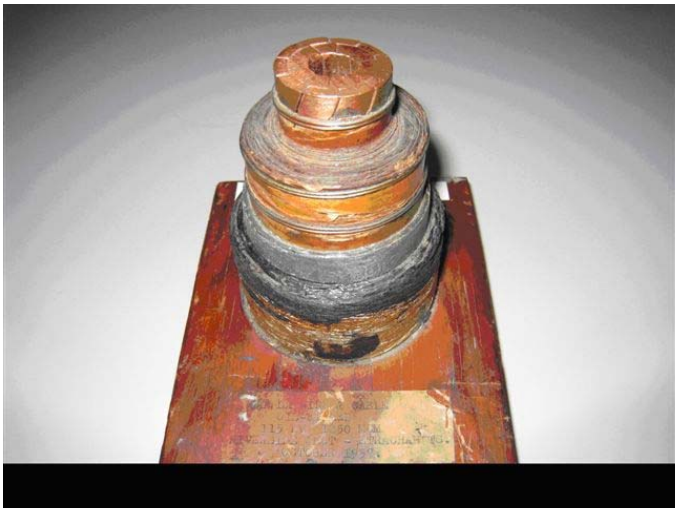

Figure 60: Low-Pressure Liquid-Filled (LPLF) Cables

High-Pressure Liquid-Filled Pipe-Type (HPLF) Cables

This cable design features the three phases of a cable circuit installed within a steel pipe. The pipe not only holds the cable phases, but also liquid maintained under high pressure (200 psi) by pumping plants located at the cable terminations. The pipe is a welded carbon steel pipe, coated on the exterior with protective coatings, and cathodically protected to prevent corrosion. The three phase conductors contained within the pipe are each wrapped with lapped paper taped insulation and an outer metallic foil tape to control voltage gradients between the conductor and the outer layers of paper insulation.

The free space surrounding the phase conductors is pressurized with insulating liquid supplied from an electrically controlled pumping plant located at the cable terminal end. Some of these pumping plants are now equipped with PLC and computer control systems, which improve operational efficiency, and have an early leak detection system.

An example of this type of cable is shown in Figure 61.

Figure 61: High-Pressure Liquid-Filled Pipe-Type (HPLF) Cable

Extruded Cross Linked Polyethylene (XLPE) Cables

This cable type is a simple design which consists of a extruded polyethylene insulation covering the phase conductor, mechanically protected by a lead sheath and covered with a polyethylene jacket to provide corrosion protection. Similar to LPLF installations, XLPE cables are installed as three individual phases in an excavated trench or concrete encased duct bank.
An example of this type of cable is shown in Figure 62.

Figure 62: Extruded Cross Linked Polyethylene (XLPE) Cables

9.0 Lines Asset Demographics

9.1 Overhead Transmission Lines Demographics

Transmission lines comprise one of the primary components in electric power systems. They are designed to transmit power over long distances and they provide the multiple interconnections between generation and load that makes up the power grid. Hydro One has 542 overhead transmission circuits having a total length of 28,438 km and 120 underground transmission cable circuits having a total length of 270 km. In the following sections we describe Hydro One's asset sustainment plans for these two types of transmission lines.

The age distribution of transmission phase conductors shown in Table 23.

		Circuit Length (Circuit -km)	(%)
Age Group	0 - 10yrs	1,015	3.57%
	11 - 20yrs	1,760	6.19%
	21 - 30yrs	2,070	7.28%
	31 - 40yrs	5,600	19.69%
	41 - 50yrs	3,113	10.95%
	>50yrs	14,880	52.32%
	Total	28,438	100.00%

Table 23: Transmission Line Population by In-Service Year

The amount of energy demand in southern Ontario resulted in fairly large amounts of energy being transmitted in a north-south direction and a very large quantity being transmitted in an east-west direction. Although the distances are shorter in Southern Ontario, the large loads being supplied along the phase conductors has meant a higher density of line construction in southern Ontario with larger conductors.

In addition, there are several points on the borders of Ontario where transmission lines are connected to neighbouring utilities in Manitoba, Minnesota, Quebec, New York and Michigan. These connection points are used for transferring energy into or out of the province as required to meet the needs of the overall area.

There are a total of 41,112 transmission wood pole structures installed on the transmission system. Of this total approximately 85% are installed on 115 kV transmission system and approximately 15% are installed on the 230 kV system, as shown in Table 24.

		Voltage Level			(%)
		115 kV	230 kV	Total	
Age Group	0 - 10yrs	4,102	12	4,114	10.00%
	11 - 20yrs	1,168	81	1,249	3.04%
	21 - 30yrs	337	105	442	1.07%
	31 - 40yrs	3,205	3,854	7,059	17.17%
	41 - 50yrs	2,077	639	2,716	6.60%
	>50yrs	23,701	1,841	25,542	62.11%
	Total	34,590	6,532	41,122	100.00%
	(%)	84.12%	15.88%	100.00%	

Table 24: Wood Pole Age Demographics

Hydro One manages approximately 81,579 hectares of rights of way for transmission lines. In addition, approximately 2000 hectares are retained for possible future transmission use and transformer stations occupy 2421 hectares. The individual Tx-ROW land areas vary in width based on the voltage level of the conductors and type of construction, with a larger portion of the lower voltage narrower corridors occurring in the North. Generation plants that supply electrical energy are located in both Northern and Southern areas of the province. With the greater industrial base and human population located in the south, there is a need to augment the southern supply with energy generated in the north. The land area for Tx-ROW in northern Ontario is 32,704 ha and 48,875 ha in the south (Tables 25). The length of the Tx-ROW in the province for different voltage levels is shown in Table 26.

		Geographic Area of Ontario	
		Northern (Hectares)	Southern (Hectares)
Voltage Class	115 kV	15,314	8,787
	230 kV	12,881	26,719
	500 kV	4,509	13,369
	Total	**32,704**	**48,875**
	(%)	40.1%	59.9%

Table 25: Transmission ROW Land Area

		Geographic Area of Ontario	
		Northern (km)	**Southern (km)**
Voltage Class	115 kV	5,050	3,268
	230 kV	3,005	6,285
	500 kV	700	2,112
	Total	**8,755**	**11,665**
	(%)	42.9%	57.1%

Table 26: Transmission ROW Lengths

9.2 Underground Cables - Demographics

Hydro One currently manages approximately 270 circuit-km of 115 kV and 230 kV high voltage cable systems that are primarily located in the urban centres of Toronto, Hamilton and Ottawa, with some minor systems in Windsor, London, Sarnia, Picton and Thunder Bay. The first cables were installed in 1951. Table 27 shows the age demographics of underground cable circuits presently in service.

		HPLF Cables		LPLF Cables		XLPE Cables		Totals		
		No. of Circuits	**Circuit Length (Circuit-km)**	**No. of Circuits**	**Circuit Length (Circuit-km)**	**No. of Circuits**	**Circuit Length (Circuit-km)**	**No. of Circuits**	**Circuit Length (Circuit-km)**	**(%)**
Age Group	**0 - 10yrs**	9	12.1	0	0	5	6.1	14	18.2	6.7%
	11 - 20yrs	6	25.1	7	3.3	1	0.3	14	28.7	10.6%
	21 - 30yrs	17	42.6	7	5.4	0	0	24	48	17.7%
	31 - 40yrs	24	66.5	1	1.8	2	0.6	27	68.9	25.4%
	41 - 50yrs	7	18.8	23	40.8	0	0	30	59.6	21.9%
	>50yrs	3	6.3	21	42	0	0	24	48.3	17.8%
	Total	**66**	**171.4**	**59**	**93.3**	**8**	**7**	**133**	**271.7**	100.0%
	(%)		63.1%		34.3%		2.6%		100.0%	

Table 27: Transmission Underground Cable Demographics

Table 28 shows that the majority of cables installed on the system are of the HPLF / LPLF type.

Voltage Class	Cable Type	No. of Circuits	Circuit Length (Circuit-km)	Total No. of Circuits	Total Circuit Length (Circuit-km)
115 kV	**HPLF**	52	137.9	95	221.4
	LPLF	42	78.8		
	XLPE	5	4.7		
230 kV	**HPLF**	14	33.5	38	49.8
	LPLF	21	14.4		
	XLPE	3	1.9		

Table 28: Voltage Breakdown of Underground Circuits

10.0 Lines Asset Performance

Line performance trends and comparisons with CEA and Canadian averages is provided in Figures 60 to 62 below.

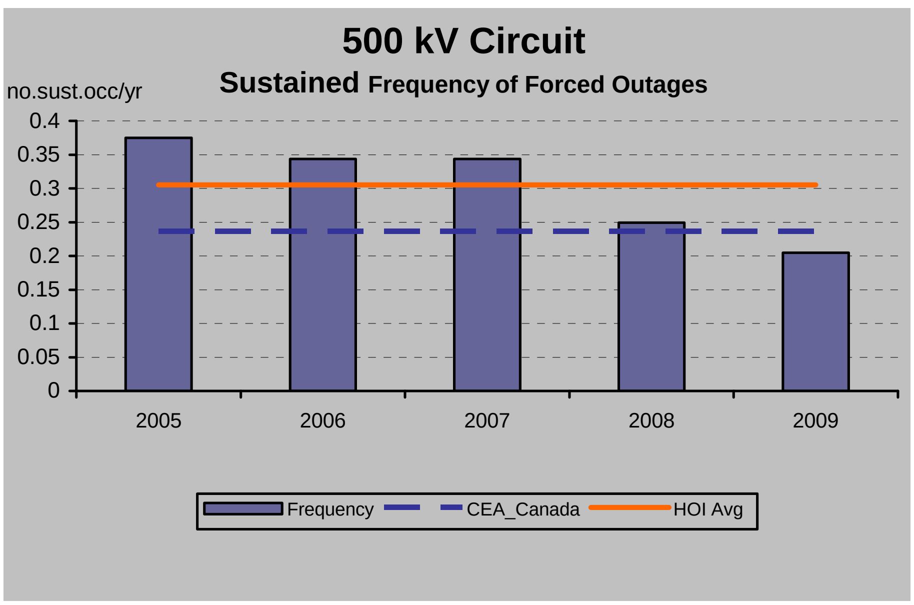

Figure 60: 500 kV Circuit Performance

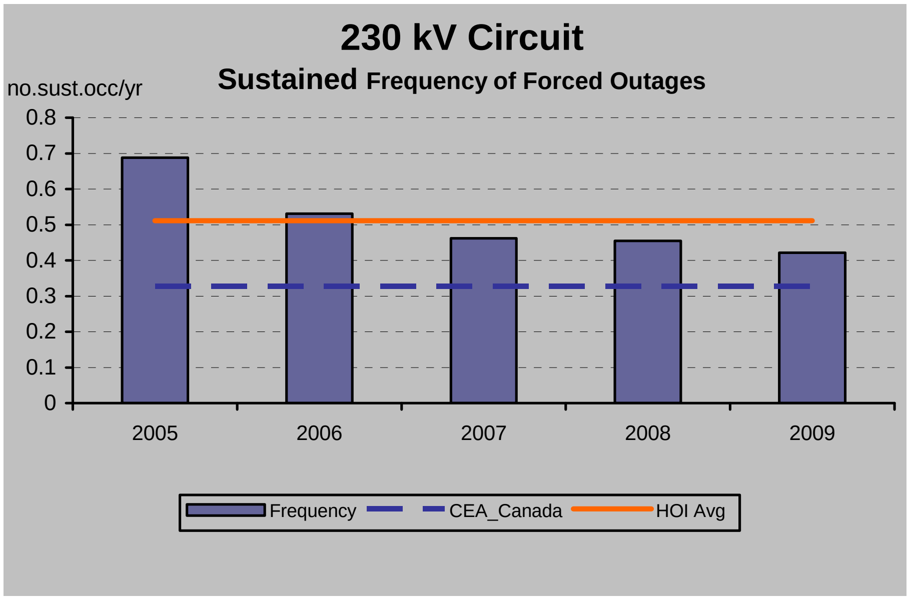

Figure 61: 230 kV Circuit Performance

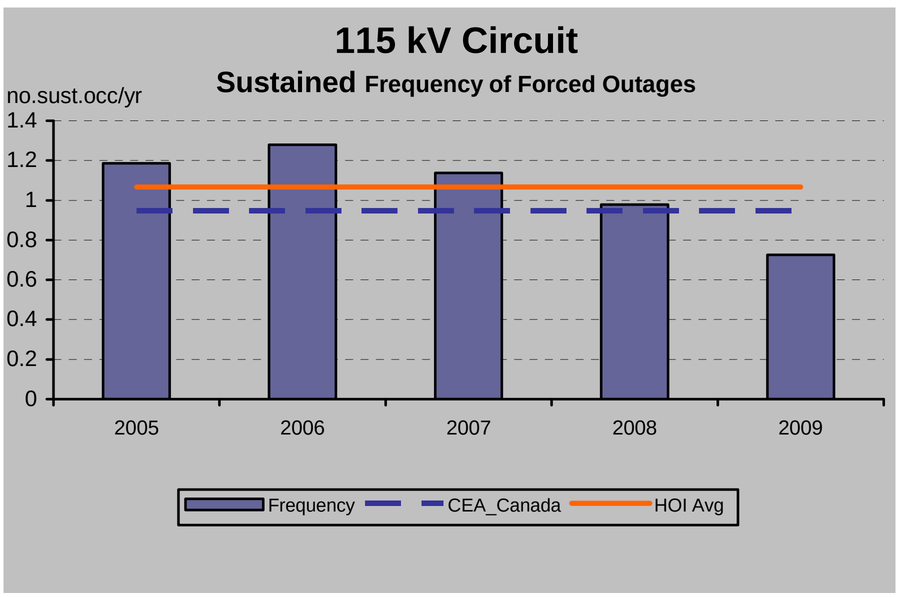

Figure 62: 115 kV Circuit Performance

While the frequency of sustained outages is relatively good and trending towards further improvement, the duration of sustained outages is high in comparison with other utilities.

SUSTAINING OM&A

1.0 INTRODUCTION

Sustaining OM&A consists of expenditures required to maintain existing transmission system facilities so that they continue to function as originally designed. The expenditures covered under Sustaining OM&A are intended to maintain equipment performance at appropriate levels, thereby maintaining the overall reliability and service quality while satisfying all legislative, regulatory, environmental and safety requirements.

Hydro One Transmission manages its Sustaining OM&A program by dividing the program expenditures into three categories:

- Stations, which funds the work required to maintain existing assets located within transmission stations including power system telecommunication facilities;
- Lines, which funds the work required to maintain overhead transmission lines and underground cables, including vegetation control on transmission lines rights-of-way;
- Engineering and Environmental Support, which funds the specialized and administrative support needed to assist with decision making processes in managing the transmission assets.

2.0 SUSTAINING OM&A SUMMARY

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 12, Schedules 4 to 6 has been completed for all Sustaining OM&A

programs to ensure that assets are managed prudently while meeting customer, operational and regulatory needs.

Exhibit C1, Tab 2, Schedule 2, contains a detailed description of the transmission assets and an outline of the sustainment investment structure. Furthermore, Exhibit D1, Tab 2, Schedule 1, provides asset demographics, asset performance data and outlines the decision process that underlies the sustaining investments.

Sustaining transmission assets is essential to the long term viability and performance of these assets and this is reinforced by the Transmission System Code that requires Hydro One to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments". Over the long term, an adequately maintained transmission system that performs to a level of its original design is in the best interest of Hydro One and its customers. As outlined in Exhibit D1, Tab 2, Schedule 1, Section 2, a greater portion of Hydro One's transmission system is reaching an age where the deterioration in condition is taking place at an increasing rate. This will place added cost pressures on future maintenance programs to maintain equipment performance and reliability and end of life asset replacements. In addition, the transmission system is in a period of expansion that will also present a need for increased maintenance expenditures when these new assets are placed into service. The programs proposed to sustain the assets address those needs identified in the test years, and do not address expected increases in future volumes of work. It must be recognized that any reductions applied to the test years spending will have a compounding effect on cost pressures in the future.

The required funding for the Sustaining OM&A in the test years, along with the spending levels for the bridge and historic years are provided in Table 1 for each of the major sustaining categories.

Table 1
Sustaining OM&A ($ Millions)

Description	Historical Years			Bridge Year	Test Years	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Stations	150.0	133.9	151.5	164.9	170.6	176.1
Lines	47.0	43.5	49.4	48.0	51.4	55.3
Engineering and Environmental Support	8.9	10.1	12.5	11.5	11.0	11.8
Total	**205.9**	**187.5**	**213.5**	**224.4**	**233.0**	**243.1**

Overall sustaining OM&A requirements for the test year 2011 have increased 3.8% over projected spending in 2010. The spending requirements for 2012 have increased by 4.3% over the 2011 requirements. The company is seeing significant cost pressures as a result of new Environment Canada regulations for PCBs, new North American Electric Reliability Corporation (NERC) regulatory requirements and aging assets that are increasing maintenance demands to maintain reliability and safety at current levels. Specific areas where the impact of aging assets is becoming apparent include stations power equipment, the deterioration in condition of specific line conductors and hardware on the 500 kV system north of Barrie. In addition, there are also cost escalation pressures. These increases are being managed through improved maintenance planning practices that include a more granular risk based approach to maintenance that will limit the increase in spending to the percentages noted above. It must be recognized that the revised maintenance planning practices are in the initial stages and the company is assuming some risk by maintaining spending at or near the 2010 levels in certain areas. Specific risks include some deterioration in reliability with a possible requirement to increase spending in the future to recover system and customer reliability to current levels.

Details concerning changes in spending over historic and the bridge year are provided in the remainder of this exhibit.

3.0 STATIONS

Transmission Station facilities are used for the delivery of power, voltage transformation, switching, and as connection points for both load and generation. Station facilities contain many of the following major components: power transformers, circuit breakers, ancillary systems, disconnect switches, bus work, insulators, potheads, surge arrestors, capacitor banks, reactors, instrument devices, protection systems, control systems, station service, grounding systems, site infrastructure and buildings.

Sustaining OM&A funding for Stations covers expenditures required to maintain the performance of the assets located within transmission stations. Hydro One Transmission manages its Stations OM&A program by dividing the program into six categories:

- Land Assessment and Remediation, a specific program that focuses on identification, mitigation and remediation of *historical* contamination located both inside and outside the station fence;
- Environmental Management, an on-going program that focuses on the mitigation and remediation of contamination located both inside and outside the station fence and manages, tests for and disposes of PCB and other regulated waste that develops as part of Hydro One Transmission's normal business practices;
- Power Equipment, which focuses on sustaining power equipment performance through planned and demand/corrective maintenance work;

- Ancillary Systems Maintenance, which focuses on sustaining the performance of ancillary systems through planned and demand/corrective maintenance work;
- Protection, Control, Monitoring, Metering and Telecommunications, which funds the planned and corrective maintenance work required to sustain power system protection, control, metering and telecommunication facilities and provides Hydro One Transmission with the information, and communication necessary to operate the transmission system; and
- Site Infrastructure Maintenance, which focuses on maintaining the infrastructure at stations through planned and demand/corrective work.

Required funding for the test years, along with the spending levels for the bridge and historical years are provided in Table 2 for each category.

Table 2
Stations OM&A ($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2007	2008	2009	2010	2011	2012
Land Assessment and Remediation	3.9	2.8	2.0	1.6	1.1	1.1
Environmental Management	8.4	(1.7)	3.5	10.9	14.0	15.4
Power Equipment	69.4	57.9	67.9	67.0	67.4	67.7
Ancillary Systems Maintenance	9.6	12.1	12.4	14.9	15.8	16.6
Protection, Control, Monitoring, Metering and Telecommunications	37.7	36.4	38.6	44.4	44.5	46.6
Site Infrastructure Maintenance	21.0	26.4	27.0	26.2	27.9	28.7
Total	**150.0**	**133.9**	**151.5**	**164.9**	**170.6**	**176.1**

Overall, sustaining OM&A requirements for Stations for the test year 2011 have increased 3.4% over projected spending in 2010. The spending requirements for 2012 have increased by 3.2% over the 2011 requirements. Spending increases are in the areas which are impacted by the new Environment Canada regulations for PCBs and the added NERC regulatory requirements. In addition, there are escalation pressures. These increases are offset for the most part through improved maintenance planning practices that include a more granular risk based approach to maintenance planning.

Details concerning changes in spending over historic and the bridge year are provided in the remainder of this exhibit.

3.1 Land Assessment and Remediation

3.1.1 Introduction

The Land Assessment and Remediation ("LAR") program is primarily focused on the mitigation and remediation of historical discharge of contaminates from station yards that may pose a risk to the public or Hydro One Transmission staff. On-site management controls are typically implemented to eliminate or mitigate on-site contamination that could result in unacceptable risks to staff, the public and/or the environment should no action be taken.

As a responsible steward committed to protecting the environment for current and future generations, Hydro One Transmission manages its operations in an environmentally responsible manner. The LAR program meets Hydro One Transmission's environmental policy objectives by assessing and mitigating on and off-property historical contamination at switching and transformer station sites. The LAR program also funds assessment and remediation work to address contamination at real estate facilities which include field service centres, administrative buildings and garage facilities.

The primary contaminants of concern are Arsenic (component of an herbicide), Polychlorinated Biphenyls (PCBs), petroleum hydrocarbons and the wood pole preservative, pentachlorophenol (PCP).

Recent changes to the Ministry of Environment (MOE) soil and groundwater standards (specifically Ontario Regulation 153/04 – Record of Site Condition – Part XV.1 of the Environmental Protection Act; amended December 29, 2009 and Ontario Regulation 153/04 – Soil, Groundwater and Sediment Standards; amended July 27, 2009), as well as changes in adjacent off-property receptor sensitivity classification, has required a review of Hydro One's LAR program as it relates to the more stringent and comprehensive regulations. The program for 2011 and 2012 includes caretaker activities at existing sites to monitor for contamination and to control contamination, as well as an assessment of sites based on the requirements of the new regulations, and minor remediation at two sites.

3.1.2 Investment Plan

The LAR Program utilizes a multi-phased approach involving successive levels of environmental site assessments, risk evaluation/prioritization and remedial option evaluations, leading to the selection of the preferred remedial/mitigating solution. The prioritization and selection process for environmental site assessment / remediation work is based on two factors: type and level of contamination that exceeds MOE standards; and the potential for the contaminants to cause adverse effects on human health and/or the environment. The MOE supports Hydro One Transmission's risk-based approach and planned programs.

For 2011 and 2012 the LAR program includes the following work:

Site Management

Once a site has been assessed or remediated, there are often regulatory requirements imposed by the MOE to monitor groundwater quality in the area of the former contamination to ensure that groundwater is not impacted. The station-specific groundwater monitoring program may be required for a period of 3-5 years, and typically involves well installations, MOE registration, groundwater measurements and sample analysis, and eventual decommissioning of the monitoring wells. Site management plans are developed to monitor and manage residual on-site contamination and to manage installed controls, such as barriers and long-term treatment systems. Planned expenditures for 2011and 2012 are $0.2 million in each year.

Site Assessment and Remediation

In order to fully understand the implication of the new regulations, site assessment is planned at a number of stations and junctions that have been identified as potential remediation sites. The assessment involves gathering information to identify actual or potential contamination and sources of contamination. This is done through a review of the site records, previous environmental reports and by analyzing soil and groundwater extracted from and around Hydro One transmission properties. Soil and water samples are taken as surface grab samples or by drilling to obtain samples from various depths. The information is analysed, risks assessed and sites prioritized for remediation. Considering that the new regulations place a higher standard for environmental management, it is expected that the outcome of the work planned for 2011 and 2012 will result in increased future expenditures to address those sites determined to be contaminated above thresholds.

Site remediation is planned at two sites. Where contamination is identified on or off Hydro One station property, a remediation plan is developed and implemented to treat, remove or otherwise manage the contamination found. The primary focus of the LAR program is to address off-site impacts and mitigate/manage on-site contamination. Where appropriate, co-ordination of LAR work with end-of-life refurbishment and capital upgrade projects are considered. Site remediation costs differ depending upon the size of the site and the remediation effort required. Planned expenditures for Studies and Site Remediation for 2011and 2012 are $0.9 million in each year.

3.1.3 Summary of Expenditures

The spending requirement for the LAR program for test years 2011 and 2012 is $1.1 million for each test year. This represents a 31% decrease over the bridge year. Spending on this program fluctuates year to year depending on the number of sites selected for remediation and the extent of the remediation work required at each site. The highest priority sites have been addressed based on previous regulations and the expectation was that the LAR program would reduce in the future. However, based on the new, and more stringent and comprehensive legislation, it is expected that in the future, costs will increase above the 2011 and 2012 levels.

The risks of not proceeding with this work in a proactive manner would subject Hydro One to punitive MOE action and/or civil litigation. As well, contaminants addressed under this program have the potential to have adverse effects on humans and must be dealt with in a proactive manner.

3.2 Environmental Management

3.2.1 Introduction

Environmental Management focuses on mitigation and remediation of contamination located both inside and outside the station fence. This program covers station waste management (PCB and regulated wastes), transformer oil leak reduction, corrective maintenance that addresses spill containment and piping deficiencies and provides funding for demand activities and to manage environmental compliance.

The funding to manage PCBs allows for testing and the proper disposal of decommissioned equipment that contains PCB contaminated waste. Environment Canada enacted new *PCB Regulations* on September 17, 2008, under the Canadian Environmental Protection Act. The Regulations govern the management of PCB equipment and material, and imposed stringent End of Use (EoU) dates for the removal and disposal of PCBs based on criteria that includes type of equipment, in-use status and PCB concentration levels. The elimination of PCBs required to meet the new regulations represents the greatest increase in the Environmental Management program.

3.2.2 Investment Plan

The Environmental Management Program consists of the following work:

PCB and Waste Management

In response to Environment Canada's new PCB Regulations, Hydro One Transmission initiated the PCB retirement program to identify and phase-out its PCB inventory to comply with the new Regulation's EoU requirements, with the exception of bushings as noted below. In accordance with the Regulations, oil-filled power equipment (transformers, breakers, instrument transformers, and associated capacitors, bushings, reclosers) located at Hydro One's Transformer Stations that contain ≥ 500 parts per million (ppm) PCB are to be retro filled or replaced by December 31, 2014 based on an extension granted to Hydro One by Environment Canada from the original date of December 31, 2009. Devices that contain ≥ 50 ppm PCB are to be retro filled or replaced by December 31, 2025.

The PCB and waste management program funds the inspection, testing and equipment retro filling of PCB-impacted oil and the proper disposal and decommissioning of PCB contaminated equipment, as well as managing the disposal of non-contaminated oils and other wastes. Hydro One Transmission's daily activities generate regulated waste, such as lead, PCB, cadmium, mercury, etc. These must be managed and disposed of in accordance with Provincial and Federal regulations. This program represents the largest component of the Environmental Management program. The expenditures for 2011 and 2012 are $7.3 million and $8.2 million respectively.

It should be noted that the above expenditures are based on anticipated regulatory relief from Environment Canada on two key issues. Hydro One Transmission and CEA-member utilities are lobbying for an extension for equipment (e.g., transformer and breakers) bushing EoU to 2025 based on outage and resource constraints. As well, the CEA membership is seeking a more favourable interpretation to the removal of oil > 2 ppm PCB for maintenance purposes. Should Hydro One not be granted the extension and a favourable ruling on oil > 2 ppm PCB, the costs for this program would approximately double.

Oil Leak Reduction

As transformers age, they are susceptible to leaks along seal gaskets and access covers, due to the effects of thermal cycling and gradual gasket deterioration. The main tank, access covers and fittings on most power transformers over 25 years of age utilize organic seal components as gaskets between flanges to retain oil. These transformers are now beginning to leak oil after performing well for the first 20 - 25 years.

Transformer oil leaks are repaired on a temporary basis when first discovered under the demand program in order to expeditiously respond to the environmental risks. These repairs are usually gap measures until a more permanent solution is implemented. Permanent repairs generally require outages and staff with a specific skill set to work on transformers. The transformers that merit permanent repairs have been identified and prioritized based on environmental and equipment considerations. On average, Hydro One completes between 3-6 transformer oil leak reductions per year. Planned expenditures for 2011 and 2012 are $3.1 million and $3.5 million respectively.

Planned and Demand Maintenance

The planned maintenance program is in place to ensure that Hydro One's spill containment systems operate as designed and to remove oil piping that is no longer in use and may contaminate the surrounding environment. As well, Hydro One Transmission has identified stations with non-functioning mechanical oil/water separator units used to drain transformer spill containment pits. Because these units do not provide the required functionality, rain and melt water that collects in the containment units have to be pumped out manually. This program will repair or replace malfunctioning pumps, adjust sensors and relays that control the pumps and ensure the system functions as required.

The demand program includes spill containment repairs, maintaining spill containment capacity for non-functioning spill containment systems by removing and disposing of the rainwater, containing and cleaning up insulating fluid spills as they occur and all other actions necessary to mitigate environmental risks posed by transmission equipment problems and failures.

Planned and demand maintenance allows Hydro One Transmission to meet its Environmental Policy objectives, by minimizing the risk to human health and the environment and by mitigating corporate exposure to legal and reputation risks. Planned expenditures for 2011 and 2012 are $2.5 million and $2.6 million respectively.

Environmental Compliance and Response Plans

The environmental compliance program encompasses activities necessary to allow Hydro One Transmission to remain in compliance with Ministry of the Environment (MOE) Certificate of Approvals (C of As) for various Transmission Stations throughout the province. Hydro One Transmission is required by the MOE to regularly test effluent as a requirement of site specific C of A documents.

Emergency Response Plans (ERP) are documents that contain important station specific information that is kept at each transmission station in the Hydro One network. The ERPs are an effective tool for planning and responding to emergencies. The plans ensure that risk of harm to employees, contractors, the public, the environment and the physical assets of Hydro One is minimized. ERPs are documents that contain important internal and external contact information, station maps and drawings as well as emergency response and evacuation procedures. Funding under this program ensures that all ERPs contain up to date and accurate site-specific information.

Planned expenditures for these activities for 2011 and 2012 are $1.1 million in each of the test years.

3.2.3 Summary of Expenditures

The Environmental Management spending requirement for test year 2011 is $14.0 million. This represents an increase of about 28% above the bridge year 2010. The increase is primarily attributed to the PCB retirement program required to comply with Federal Regulations as well as an increase in transformer oil leak reduction. The spending for the test year 2012 is $15.4 million which is an increase of 10% over test year 2011. The increased spending is primarily driven by the PCB retirement program.

A reduction of this program would result in an inability for Hydro One to meet Environment Canada PCB regulations. As well, a reduction would subject Hydro One to punitive action by the MOE for non compliance in areas of oil spills and C of A requirements. Reduced spending in oil leak reductions and repairs to spill containment systems would increase the risks of major oil spills and increase site contamination with potential for off-site migration, thereby evoking environmental noncompliance penalties.

3.3 Power Equipment

3.3.1 Introduction

Transmission power equipment includes maintenance on Hydro One Transmission's 1467 transmission transformers, 4,448 circuit breakers, about 14,000 switches and station bus work, as well as capacitor banks and reactors. Transformers are mainly used to connect two systems at different voltages and provide voltage control. Circuit breakers provide protection to the system under fault conditions and enable switching (energization and de-energization of system elements) under normal operating conditions. Switches keep transmission system elements either connected or disconnected for the purposes of transmitting electricity or performing maintenance. Station bus work connects various station components within the station.

The maintenance of Hydro One Transmission's power equipment is the most significant program within the Stations category of expenditures. This program covers costs to sustain power equipment performance through planned and demand/corrective maintenance work. The planned work includes:

- Scheduled preventative maintenance and condition based equipment maintenance,
- Transformer and breaker mid-life refurbishment to ensure their life expectancy is realized,
- Maintenance of strategic spares,
- Collection of asset condition information.

The demand/corrective maintenance work includes corrective maintenance, emergency response to system and equipment problems and repair following equipment failures.

3.3.2 Investment Plan

The power equipment programs are categorized as follows:

Preventive Maintenance

Preventive maintenance is conducted to meet Hydro One's obligations defined by the Transmission System Code to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments". The following equipment has either time based or condition based maintenance activities defined for them: breakers, capacitor banks, instrument transformers, reactors, switches and station transformers. There is also a small amount of maintenance done on general power equipment such as back-up generators and station bus structures.

Hydro One Transmission's Preventive Maintenance Optimization (PMO) program for power equipment is based on industry recognized Reliability Centered Maintenance (RCM) principles. The effectiveness of the PMO maintenance program depends on a continual improvement process and how consistently asset condition and performance information is collected and analyzed. The RCM principles utilized in the PMO program provides structured methodology to ensure that equipment functionality requirements are met and to determine inspection criteria based on known equipment failure modes.

PMO places a priority on the performance of predictive/diagnostic activities (condition based monitoring) such as visual inspections, load testing, function testing and equipment performance monitoring rather than the more intrusive time based activities. Different equipment types within the Power Equipment program have varying maintenance activities and in many cases at different frequencies. More specifically, examples of maintenance activities for transformers, breakers and switches include:

- Regular visual inspections on all equipment to identify and record defects

- Identify oil leaks and record pressure (oil and air), temperature on specific equipment types.
- Function test various equipment elements and alarms to ensure continued operation, reliability and identify issues, and top up oil as required.
- Selective intrusive maintenance to assess equipment condition, check contacts, test components, clean and lubricate, replace seals and complete minor repairs as required.
- Diagnostics include oil analysis for dissolved gas, moisture content, dielectric strength assessment and insulator testing.

The frequencies of these activities vary depending upon the make, model type and condition of the subject equipment.

The planned expenditure in 2011 and 2012 is $21.7 million and $23.2 million respectively. Costs are based on the volume and type of maintenance work to be completed during the calendar year.

<u>Planned and Demand Corrective Maintenance</u>

Corrective Maintenance spending is set based on historical demands on the system and to address known problems. Demand Corrective Maintenance spending takes place in two areas: Discovery Corrective and Unplanned Corrective Maintenance that includes emergency response.

Discovery Corrective work is unplanned work that was discovered during the course of Planned Maintenance activities. If for example, during testing, the breaker contact travel was incorrect, maintenance staff would make the necessary adjustments at that time rather than schedule another planned outage.

Unplanned Corrective Maintenance results from all unscheduled, non-programmed maintenance necessitated by unforeseen problems and/or equipment failure. Corrective maintenance is required to address the risk of harm and / or damage to any or all of employee safety, public safety, system reliability or the environment. Emergency response may include preliminary investigation and minor or make safe repairs following equipment failure. Expenditures for planned and demand corrective for 2011 and 2012 are $22.1 million and $ 22.6 million respectively.

<u>500 kV (750 MVA) Transformers Refurbishments</u>

The refurbishment of the 750 MVA autotransformers is required to address the high failure rates of this critical class of equipment. Since 2000 there have been four 750 MVA transformer failures. Investigations that included third party design reviews have revealed a number of design limitations and that the moisture level in these units can reach unacceptably high levels and can lead to catastrophic failure, as has occurred and will continue to occur without continued remediation. A failure of a 750 MVA transformer jeopardizes the reliability of the 500 kV system to which it is connected which can further impact the stability of the electricity grid resulting in power outages that impact customer supply as well as constrain generation. A remediation program which includes a thorough dry out was started in 2006 to address the primary deficiencies. The current remediation program is expected to conclude by the end of 2012. Planned expenditures for 2011 and 2012 are $5.8 million and $3.2 million respectively.

115 kV & 230 kV Transformer Refurbishments

Activities included under this program are transformer mid-life overhauls, radiator refurbishment, painting of the transformer shell, Under Load Tap Changer (ULTC) modifications and upgrades. These refurbishment expenditures are cost effective, will extend the asset life, maintain system and customer reliability and defer capital expenditures.

The scope of work for transformer mid-life refurbishment considers the overhaul or replacement of components to maintain reliable service with regular maintenance for at least 15 years. This program can address active oil leaks on the main tank, replace worn cable systems, overhaul all bushings, overhaul oil valves, repaint the main tank and radiators, repack radiator valves, replace gas relay piping with socket weld system, replace missing or defective cooling fans and install replacement low maintenance conservator tank breathers. Planned expenditures for 2011 and 2012 are $7.2 million and $ 7.6 million respectively. Spending is based on the number and type of transformers scheduled for refurbishment during the specific calendar year.

Breaker Refurbishment

There are a number of different breaker refurbishment programs within the Power Equipment program. They are dependent upon the type of breaker and condition issue. These include, Air Blast Circuit breaker auxiliary component refurbishment program, Gas Insulated Switchgear (GIS) breaker hydraulic system refurbishment, GIS breaker refurbishment program, Oil Circuit Breaker (OCB) bushing /component refurbishment program and SF6 mid-life refurbishment program.

The nature of the work would vary widely depending upon the make, model type and specific issue being addressed. As an example, the Air Blast Circuit Breaker (ABCB) ancillary component refurbishment program is the most significant breaker refurbishment program. This program has been ongoing since 2004 with the aim of increased reliability and lowering risk for those breaker types that suffer poor performance. This program includes refurbishment of breaker control components, gaskets, contacts, pressure switches, installation of control cabinet insulation and modifications to control cabinet space heaters. These components have reached 25 to 30 years of age, are approaching end of useful life, which is approximately 40 to 55 years, and must be managed well to provide a reliable level of service until end of life replacement under capital programs. Planned expenditures for 2011 and 2012 are $ 4.0 million and $ 4.1 million respectively. Spending is based on the number and type of breakers scheduled for refurbishment during the specific calendar year.

Other Maintenance and Inspection Programs

Maintenance activities under this category include nuisance wildlife control, maintenance required for strategic spares and miscellaneous maintenance as outlined below.

Nuisance wildlife control programs are in place to combat the effects of both equipment interruptions and customer outages that can result when wildlife enter Hydro One transmission stations for various reasons such as shelter, food, breeding and hibernation. This program also helps towards eliminating health and safety risks, e.g., racoon round worm, and provides training to employees to assist with the overall control efforts. Animal related outages have averaged about 25 per year prior to preventive action being taken at targeted sites. Since the inception of the program, the number of outages has reduced by about 50% at the targeted sites.

An inventory of circuit breakers and transformers is maintained in storage in the event of a system component failure. Maintenance is required to ensure that these components are available for service at any given time and not to void manufacturer warranties. The frequencies and type of maintenance performed is based upon make and model type as discussed in sections previously.

There are several other programs within power equipment that account for the remainder of the funding requirement. These include capacitor bank maintenance, equipment protective recoating, insulator contamination monitoring and power washing, station string insulator testing program and station asset condition assessment activities. All of these activities are essential to ensure customer and system reliability and manage equipment in a prudent and sustainable manner.

Planned expenditures for these programs in 2011 is $6.6 million and for 2012 is $7.0 million. Spending is based on historic costs, number of sites slated for animal mitigation and volume of maintenance activities.

3.3.3 Summary of Expenditures

The spending requirements for the test years 2011 and 2012 are $67.4 million and $67.7 million respectively. These spending levels are almost identical to that of the bridge year. As noted in Exhibit D1, Tab 2, Schedule 1, Section 2, it is apparent that stations power equipment is aging and thereby placing added pressures on maintenance with corresponding increases in expenditures. Hydro One recognizes these cost pressures and has closely reviewed its maintenance practices using the functionalities of its new work management system (SAP), and has structured its maintenance programs to keep costs in check and still manage reliability and safety risks to acceptable levels over the two test years.

The risks of not proceeding with these levels of work include:

- Scheduled power equipment maintenance will not be completed, resulting in increased risks to equipment unavailability and degradation in equipment performance. Currently Hydro One's primary station equipment performance is below CEA average (refer to Exhibit D1, Tab 2, Schedule 1, Section 3.0) and a reduction in maintenance will lead to a continuation of poor performance, placing added risks on customer and system reliability.
- Reductions in transformer and breaker mid life refurbishment will ultimately increase life cycle costs for these assets as they will fail prior to expected service lives, e.g., transformers 40 to 65 years.
- Increased failures of transformers, oil circuit breakers and SF6 breakers will have an adverse effect on the environment and will result in increased expenditures associated with clean-up and added mitigation to prevent re-occurrence.
- Corrective maintenance expenditures will increase if planned maintenance is deferred and create significant pressure on capital replacement programs due to reductions in ongoing maintenance.
- Reduced diagnostics and asset condition assessments will result in suboptimal decisions on capital replacements and maintenance.
- Reductions in this program will manifest themselves in the form of reduced system and equipment performance with a reoccurrence of transformer failures as experienced in the past.

3.4 Ancillary Systems Maintenance

3.4.1 Introduction

Ancillary Systems are required at all Hydro One Transmission's 281 stations. These systems are comprised of station service systems, high pressure air ("HPA") systems, inverters, grounding systems, batteries, battery chargers, instrument transformers, surge arrestors, potheads, low voltage cables and oil processing facilities. These systems provide key services and operating support to all of the various station components.

The planned work funds preventive maintenance activities, major component overhauls to ensure expected equipment life is realized, collecting asset condition information, and periodic tests and inspections required to satisfy reliability, safety and regulatory requirements. The requirements of oversight bodies such as the Technical Standards and Safety Authority, IESO, NPCC, Ministry of Health (Occupational Health and Safety Act) and the MOE impose regulatory requirements and in some cases mandated inspection and testing cycles on ancillary equipment.

The demand/corrective work funding covers unforeseen corrective maintenance expenditures, emergency response and repairs following equipment failures.

3.4.2 Investment Plan

The Ancillary Systems Management Program consists of the following work.

Preventive Maintenance

The Preventive Maintenance program is the dominant program in Ancillary Maintenance. Similar to Power Equipment, the preventive maintenance program is founded on PMO principles and is comprised of data collection through PMO activities and includes minor repairs as the need arises and where economical.

Equipment data is collected through PMO related diagnostic and maintenance activities. Information is also collected on equipment performance and the consequences of equipment failure to system reliability. Specific equipment knowledge, gathered through Hydro One Transmission's own evaluations and manufacturer's data, is also required.

This information is used to set future maintenance and determine end of life replacements in order to manage equipment performance, system reliability, safety and regulatory requirements.

PMO utilizes predefined standards for preventive maintenance activities and places a priority on the performance of predictive/diagnostic activities (condition based monitoring) such as visual inspections, load testing, function testing and equipment performance monitoring rather than the more intrusive time scheduled activities. In many cases equipment types within the ancillary program have different types of maintenance performed at different frequencies. As an example, inspections are carried out on station batteries every 6 months whereas a battery load test is carried out every 5 years. The total number of planned maintenance activities per year in ancillary maintenance is in the order of 9,000.

Planned expenditures in 2011 and 2012 are $8.4 million and $8.8 million respectively. Costs are based on the volume and type of maintenance work to be completed during the calendar year in question.

Planned and Demand Corrective Maintenance

Corrective Maintenance spending is based on historical demands on the system and to address known problems under a planned basis.

Planned corrective maintenance includes upgrading to grounding systems to ensure safety and maintain equipment operation, testing and repairs of problematic high pressure air systems, station service repairs and copper theft deterrent initiatives such as installation of conduit over transformer neutrals.

Demand corrective maintenance spending takes place in two areas: Discovery Corrective and Unplanned Corrective Maintenance that includes emergency response as described under Power Equipment in this exhibit, please refer to section 3.3 for added details.

Planned and demand corrective expenditures for 2011 and 2012 are $5.1 million and $5.3 million respectively.

Other Maintenance Activities and Costs

Other maintenance activities includes grounding studies, funding for Hydro One's oil farm operation at its Central Maintenance Facility, Asset Condition Assessments at Hydro One's shared facilities with generators and fees paid for services at these shared facilities.

Hydro One has a number of sites located within or adjacent to generating stations (Hydraulic, Thermal and Nuclear) where services are purchased directly from the plant in order to maintain switchyard operations. These services include AC/DC station service, water and snow removal. Agreements are in place between Hydro One Transmission and the generating entities with respect to what services are shared and appropriate compensation. Hydro One Transmission is billed on an annual basis for these services.

Planned expenditures in this category for 2011 and 2012 are $ 2.3 million and $ 2.6 million respectively.

3.4.3 Summary of Expenditures

The spending requirement for test year 2011 is $15.8 million, which is an increase of 6.0% over the bridge year 2010. Spending for test year 2012 is $16.6 million which is an increase of 5.0% over the spending in test year 2011. The reason for the increase is attributed to added collection of ACA information related to shared switchyard facilities with generators, as well as some increase in preventative programs to acquire information on this aging class of assets.

The risks of reduced spending on Ancillary Systems Maintenance will result in increased corrective costs, increased pressure on capital replacements due to increasing equipment failures, compliance issues and potential punitive action by Regulatory bodies, as well as a decline in performance of power equipment assets that rely on the secure supply of AC/DC power and high pressure air.

3.5 Protection Control, Monitoring, Metering and Telecommunications

Protection, Control, Monitoring, Metering and Telecommunications funds the programs required to sustain power system protection, control, metering and telecommunication facilities.

Hydro One Transmission manages its Protection, Control, Monitoring, Metering, and Telecommunications OM&A by dividing the program into three categories:

- Protection, Control, Monitoring and Metering Equipment Maintenance, which funds the planned and demand/corrective maintenance work required to sustain the performance of protection, control, monitoring and metering equipment;
- Cyber Security, which funds the planned and demand/corrective maintenance work to sustain the systems and facilities required to achieve and sustain compliance with the NERC Critical Infrastructure Protection (CIP) Standards; and
- Telecommunications, which funds the planned and corrective maintenance work required to sustain power system telecommunication facilities which provides Hydro One

Transmission with the information, and communication necessary to operate the transmission system.

Required funding for the test years, along with the spending levels for the bridge and historical years are provided in Table 3 for each of these categories.

Table 3

Protection, Control, Monitoring, Metering, and Telecommunications OM&A ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Protection, Control, Monitoring and Metering Equipment Maintenance	21.1	19.0	18.7	22.7	20.7	21.7
Cyber Security	0.8	0.7	1.9	4.8	6.1	6.3
Telecommunications	15.8	16.7	18.1	16.9	17.7	18.6
Total	**37.7**	**36.4**	**38.6**	**44.4**	**44.5**	**46.6**

Protection, Control, Monitoring, Metering and Telecommunications spending for 2011 is about the same as the projected spending for 2010. The spending requirement for 2012 is 4.7% over the 2011 requirements. Spending increases are in the areas impacted by the new regulatory requirements mandated by NERC and the expansion of the grid. These increases have been offset for the most part through risk based reductions in selective maintenance activities.

Details concerning the changes in spending over historic and the bridge year are provided in the remainder of the section.

3.5.1 Protection, Control, Monitoring and Metering Equipment

3.5.1.1 Introduction

Protective relays and their associated systems (e.g. telecommunications) are devices connected throughout the Transmission Network for the purpose of sensing abnormal conditions (e.g. as a result of natural events, physical accidents, equipment failure). Upon sensing an abnormal condition, protection systems immediately operate appropriate circuit breakers to isolate the affected equipment (e.g. transmission line, transformer, generator, buswork, etc.) from sources of energy and the rest of the transmission system. Failure to promptly isolate abnormal conditions can cause a widespread blackout and catastrophic destruction of equipment as well as injury to workers and the public. Protective relays and their associated systems are essential for the safe and reliable operation of the Transmission Network. Any system element for which protections are not functioning must be removed immediately from service.

Control systems are used to perform control, monitoring, and alarming functions for each station remotely from the Ontario Grid Control Centre (OGCC), the back-up control centre, or locally at the station. Control systems also provide real time data to the IESO's Energy Management System in accordance with the market rules. Control systems include Remote Terminal Units ("RTUs"), Local Controllers and Programmable Synchrocheck Relays (PSR) that are located in the stations. RTU's provide the interface to all of the equipment in a switchyard and are the essential control system for stations. The complete control system for the grid also includes gateway systems, telecommunications and the central control systems located at the OGCC and its back-up. Maintenance of the over 460 RTU's on Hydro One Transmission's system, and the provisioning and maintenance of telecommunications equipment, are part of this program.

Monitoring systems provide detailed, high speed records of normal and abnormal events that occur in stations or on transmission lines. These systems are required to meet NPCC and IESO requirements. In addition to meeting NPCC and IESO requirements, the information obtained from monitoring is also used for maintenance scheduling, diagnostic evaluations and post-mortem event analysis, consistent with good utility practice. Monitoring systems include Sequence of Event Recorders (SER), Digital Fault Recorders (DFR) and Power System Disturbance Recorders (PSDR).

Wholesale revenue meters are used to measure energy flow between the IESO controlled power grid and metered market participants in accordance with Measurement Canada requirements for transaction settlements. Historically, these meter installations were included in Hydro One Transmission's asset base, but in accordance with the market rules, at the earliest expiry date of any meter seal forming part of a metering installation, the metered market participant must take ownership of the metering installation and make arrangements to comply with the market rules. As of year end 2009, 174 metering points remain in Hydro One Transmission's asset base under transitional arrangements.

3.5.1.2 Investment Plan

The expenditures for maintenance of Protection, Control, Monitoring and Metering Equipment fall into three categories:

<u>Re-verifications</u>

Protection systems spend most of their service life in a dormant state, yet must be relied upon to perform flawlessly during a fault or other abnormal condition. The only means to maintain a high degree of certainty that the scheme will operate correctly when called upon, is to perform a test. For those portions of the grid designated as Bulk Power System, NPCC mandates the frequency at which these tests must be performed. For other portions of the Grid, the testing frequency follows Hydro One policy. For portions of the grid where a protection failure can have only very localised impact, protections are verified by a combination of visual inspections and detailed analysis of events. This is the case for protections on feeders that emanate from a transformer station to supply the distribution system.

Revenue Meters are also subject to periodic re-verification of their accuracy. These re-verifications are referred to as "re-seal" and are done at a frequency mandated by the Electricity and Gas Inspection Act and regulations overseen by Measurement Canada.

The planned expenditure for re-verifications is $6.3 million in 2011 and $6.7 million in 2012. The cost of this program fluctuates based on the actual numbers of protections and meters that come due for re-verification each year and it is expected this program will increase in the future due to the added protection schemes resulting from the expansion of the grid, and due to increased need for feeder protection event analyses due to distribution connected generation.

Corrective Maintenance

All P&C and telecommunication assets experience some rate of failure or defect during their normal useful life. As they approach end of life the rate of failures increases and the cost of correcting failures increases due to lack of vendor support and difficulty obtaining spare parts. Due to the criticality of P&C assets and their large population sizes, increasing rates of failure cannot be tolerated as the consequences would include equipment damage and wide spread power outages.

Corrective work is driven by the historic rate of correctives plus information on specific corrective issues that need to be addressed. Specific corrective issues discovered include problems discovered from analysis of events and defects with certain makes and models of protections which have been identified to be problematic and jeopardize reliability of the electrical system. Expenditure for corrective maintenance is $7.5 million in 2011 and $7.8 million in 2012.

Support Processes and Systems and Preventative Maintenance

Hydro One Transmission maintains systems to manage change control of the settings and configuration of protection and control systems, keeps records of events, as well as the inventory and re-seal schedule for revenue meters. Processes are in place for carrying out event analyses and follow-up actions, doing routine inspections, managing spare parts and tracking vendor advisories. The cost for support processes and systems is increasing due to new processes and systems required to meet new or more stringent reliability standards, and due to expenditures to augment the asset condition assessment of protection systems.

Preventative maintenance activities required for Protection, Control and Monitoring systems includes replacement of internal batteries that are used to power clocks and configuration memory on various pieces of monitoring and control equipment and replacement of isolation devices on RTU's.

The planned expenditure for support processes and systems and preventative maintenance is $6.9 million in 2011 and $7.2 million in 2012

3.5.1.3 Summary of Expenditures

The spending requirement for this program for test year 2011 is $20.7 million which is reduction of 8.8% from bridge year 2010. The spending requirement for 2012 is $21.7 million which is an increase of 4.8% over the 2011 spending. The reduction in spending from the bridge year is as a result of fewer protections in need of re-verification as a result of risk based adjustments to the maintenance program. The increase in spending in 2012 is attributed to greater level of defect corrections and re-verifications over 2011 levels.

Reductions in this program will lead to an increase in protection and control failures which will result in one or more of: equipment outages, equipment damage, load interruption and a wide spread interruption to the interconnected electrical system. Furthermore, reductions in these programs will result in Hydro One Transmission failing to comply with NPCC and NERC reliability requirements.

3.5.2 Cyber Security

3.5.2.1 Introduction

Cyber Security assets include firewalls, electronic intrusion detections system, and facilities for virus scanning, event logging, physical access control and video surveillance. The Canadian and US Federal governments categorize the energy sector as a critical infrastructure. To protect the reliability of the interconnected grid, the North American Electric Reliability Corporation (NERC) developed an initial set of eight new Critical Infrastructure Protection standards (CIP002-CIP009), also referred to as the "Cyber Security" standards. Hydro One Transmission has implemented cyber and physical barriers for critical cyber assets in order to comply with the 80 plus requirements of these standards. The standards require regular testing and updating of the security systems and procedures for changes that occur in staffing as well as in the transmission assets that require security.

3.5.2.2 Investment Plan

Maintenance and system support for Cyber Security include the following:

- Maintaining the various Cyber Security assets (e.g. Firewalls, Intrusion Detection Systems, Malware detection systems, Physical Security systems)
- Conducting required annual surveys of critical cyber assets and security perimeters
- Recurring tasks associated with systems management (e.g. maintaining personnel access lists, patch management, maintaining logs, updating firmware, periodic tests)

3.5.2.3 Summary of Expenditures

Cyber Security for test years 2011 and 2012 are $6.1 million which is an increase of 27% over the bridge year 2010. The increase over the bridge year is due to the required expanded coverage of the Cyber Security process to include critical telecommunication systems and the addition of a number of critical assets. The spending for 2012 represents an increase of 3.3% over 2011 which is necessary for further increases in the number of Cyber Assets and management of new vulnerabilities.

The requirement for full compliance came into effect on December 31, 2009.

3.5.3 Telecommunications

3.5.3.1 Introduction

Telecommunication systems provide high reliability and high-speed communications required for the protection of Hydro One Transmission's system and for monitoring and control of the power system. Hydro One Transmission's telecommunication system consists of digital fiber-optic networks, Power Line Carrier (PLC) systems, owned or leased metallic cables, digital microwave, and the associated auxiliary telecommunication equipment for each.

3.5.3.2 Investment Plan

The expenditures for Telecommunications fall into three categories:

Maintenance

Telecommunication Assets include the terminal equipment for Power Line Carrier Systems, SONET equipment, Multiplexors, Neutralizing Transformers, Tone Equipment, Radios and Batteries. The maintenance of these assets includes corrective maintenance as well as replenishing spare parts inventories. The planned cost for maintenance of telecommunication assets is $4.9 million in 2011 and $5.2 million in 2012.

Leased Telecommunication Circuits

Leased telecommunication circuit costs include the monthly fees of the various telecommunications required for protection and control as well as for the provincial mobile radio system. These costs are $7.4 million in 2011 and $7.8 million in 2012.

Hydro One Telecom Contract

Hydro One Networks contract for services from Hydro One Telecom (HOT). These services include monitoring and alarm response for the power system telecommunication circuits, outage management, vendor management, system analysis and updating the computer systems that are used in management of the telecom circuits. The cost for these services by HOT is $5.4 million in 2011 and $5.5 million in 2012.

3.5.3.3 Summary of Expenditures

Telecommunications expenditures in test years 2011 and 2012 are $ 17.7 million and $18.6 million respectively. Spending in the test year 2011 is 4.7% more than the bridge year 2010, due mainly to an increase in corrective maintenance to address and restore communication reliability. Telecommunications OM&A for test year 2012 is 5.1% more than the 2011 spending level due mainly to an increase in leased circuit cost due to new facilities being placed into service.

Reductions in this program would increase the risk of loss of communication with significant impacts on the power system and worker safety. Loss of OGCC communication with controls at stations could violate IESO market rule requirements and would require staff to be deployed to stations for the purpose of switching. Loss of communications with and between protections would result in a requirement to remove lines from service until protections are restored.

3.6 Site Infrastructure Maintenance

3.6.1 Introduction

The Transmission Site Facilities & Infrastructure Systems are comprised of yard surfacing, drainage, fire protection and detection, station security systems, structural footings, station buildings, cranes, elevators, heating ventilation and air-conditioning (“HVAC”), access roads, water supplies, sewage, oil systems, spill containment systems and fences at Hydro One’s 281 transmission stations. These systems provide the infrastructure required to prevent unauthorized access, enable access for authorized staff and make the station site functional for equipment and staff.

This program funds planned and demand maintenance at station facilities to ensure that these remain in a safe condition and in compliance with regulations, as well as grounds maintenance and site security at transmission stations.

3.6.2 Investment Plan

The investment plan for this work program is extensively driven by assessment of data collected, historical levels of spending for demand work, as well as regulatory requirements and corporate standards. Regulatory requirements include building and fire codes, the Occupational Health and Safety Act and the Ministry of Environment requirements, as well as community by-laws.

The Site Infrastructure Maintenance Program consists of the following:

Facilities and Infrastructure Maintenance

Data and information on the condition of station sites and buildings is collected through regular inspections, as well as information gathered during maintenance work and trouble call response. Contracted inspections and asset surveys are also conducted.

The preventative and corrective maintenance program for site infrastructure and site facilities is the dominant program and contains a wide variety of activities such as building maintenance and facility improvements, HVAC maintenance, inspections, janitorial services, water system maintenance and testing, roads, bridges and railway maintenance and station Civil/Geotechnical and Asset Condition Assessments. The corrective maintenance program for site infrastructure is based upon historic averages for demand corrective including trouble calls related to station infrastructure facilities. The planned corrective is based on identified defects that need to be addressed in the test years. Spending for preventative and corrective maintenance on facilities is $17.3 million in 2011 and $17.8 million in 2012.

Grounds Maintenance

Grounds maintenance involves the application of herbicides to control weeds and vegetation inside Hydro One's transformer stations. Weed and vegetation control is required to keep step and touch voltages at safe levels for workers and others that enter the station. In addition, grounds maintenance includes snow removal to allow access to and within a station, grass cutting, clean-up and general maintenance that may be required for site drainage and grading. Spending for grounds maintenance on transformer station facilities is $5.0 million in 2011 and $5.1 million in 2012.

Site Security

Site security encompasses a number of activities. These include preventative and corrective maintenance at station perimeters, (e.g., fences and gates) to prevent unauthorized access and in some cases includes security guards at locations where there is a high occurrence of vandalism. Furthermore, this program includes a number of security measures to deter theft of copper and to control entry of nuisance wildlife that have and continue to be responsible for equipment and station outages. Hydro One is experiencing a high number of occurrences of copper theft. Not only does theft of copper result in significant damage to site facilities, but missing copper on equipment and a break in the ground grid creates unsafe conditions for workers and the public, and in some cases requires that equipment be taken out of service until repairs are made. Copper theft is dangerous to thieves, creates unsafe conditions for workers and has negative implications on equipment and system reliability, and considering the frequency that these are occurring, Hydro One Transmission has and will continue to implement deterrents and measures to reduce theft. As a result, costs have increased in this area over historic spending. Spending for site security at transmission stations is $5.6 million in 2011 and $5.8 million in 2012.

3.6.3 Summary of Expenditures

The spending requirement for test year 2011 is $27.9 million which is an increase of 6.5% over bridge year 2010. Spending for the 2012 test year is $28.7 million which is an increase of 2.9% over test year 2011. The primary reasons for these increases are attributed to an increase in site security to deter copper theft and added facility requirements to support staff additions required to deliver on the larger capital work programs.

Reductions in site security will result in a reduced ability to deal with copper theft, thereby jeopardizing safety and reliability, as well as increases in repair costs. Reductions in snow removal can extend outage durations due to reduced access and will increase time to access equipment for routine maintenance, thereby increasing costs. Reductions in preventative and corrective maintenance will mean that insufficient condition information is available for optimum planning. As well, there is a risk of non compliance with environmental regulations governing water systems and sanitary sewers.

4.0 LINES

Transmission lines are used to transmit electric power, via integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or to local distribution companies, including Hydro One Distribution, who in turn distribute the power to end-use customers. Hydro One Transmission's lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV. The Company's transmission line system consists of approximately 28,600 circuit km of overhead transmission lines located on about 21,000 km of rights of way, and 280 circuit km of underground transmission lines.

Overhead transmission line components include structures (steel, wood or aluminum) and corresponding foundations, conductors, shieldwires, insulators, lightning arrestors, hardware, switches, and grounding systems. Underground transmission line components include cables, terminations, oil pressure systems and grounding systems. The underground transmission lines are generally located in large urban centers.

Sustaining OM&A funding for Lines expenditures is required to maintain existing overhead and underground transmission lines assets. Hydro One Transmission manages its Lines OM&A program by dividing the program into three categories:

- Vegetation Management, which ensures that clearances to energized equipment are maintained and includes brush control, line clearing, condition patrol, demand maintenance and ground maintenance.
- Overhead Lines Program**s**, which includes Preventative Maintenance & Asset Condition Assessment, Trouble Calls, Planned Corrective Maintenance & Projects.
- Underground Cable Program**s**, which focuses on inspections, analysis, tests, surveys and diagnostics of cables, vaults, jackets and potheads as well as condition and route patrols and corrective maintenance.

Required funding for 2011 and 2012, along with spending levels for the bridge and historic years for each program are provided in Table 4.

Table 4
Lines Sustaining OM&A ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Vegetation Management	27.0	20.7	25.7	26.6	27.5	28.3
Overhead Lines Programs	16.5	19.0	19.4	17.9	20.2	23.0
Underground Cable Programs	3.5	3.7	4.4	3.5	3.8	4.0
Total	**47.0**	**43.5**	**49.4**	**48.0**	**51.4**	**55.3**

Overall, sustaining OM&A requirements for Lines for the test year 2011 have increased 7.1% over projected spending in 2010. The spending requirements for 2012 increased by 7.6% over the 2011 requirement. The primary reasons for the increases are attributed to defects that need to be addressed on the 500 kV lines between Barrie and Timmins and repair and retrofit conductor at supports on the 115 kV and 230 kV system in southwestern Ontario due to damage caused by aeolian (wind induced) vibration.

4.1 Vegetation Management

Hydro One Transmission has approximately 21,000 km of transmission lines that occupy approximately 82,000 hectares of rights of way. These lands contain varying types of vegetation, from forests to grass lands, some of which can grow into the proximity of transmission lines and threaten system reliability. To ensure a sustainable level of reliability, a vegetation management program is required to ensure that clearances between vegetation and energized equipment are maintained. The program controls vegetation growth in a manner that considers environmental, ecological and social impacts, by undertaking various activities including tree removal and trimming, brush control, condition patrols, grounds maintenance and responding to reliability and landowners concerns. These activities are separate packages of work and are generally not completed at the same time. In addition, staff required to complete the work have a varying degree of skills depending on the type of work involved.

Table 5 outlines the proposed funding for 2011 and 2012 for the specific elements of the program as well as the spending levels for the bridge and historic years.

Table 5
Vegetation Management ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Brush control	16.3	11.1	16.0	15.8	16.2	16.7
Line Clearing	4.2	3.6	3.9	4.3	4.4	4.5
Property Owner Contact	1.2	1.1	1.0	1.2	1.2	1.3
Condition Patrols	1.6	1.0	0.9	1.3	1.5	1.6
Demand Maintenance	1.0	1.4	1.3	1.4	1.4	1.4
Grounds Maintenance	2.7	2.5	2.7	2.6	2.7	2.8
Total	**27.0**	**20.7**	**25.7**	**26.6**	**27.5**	**28.3**

4.1.1 Brush Control, Line Clearing, & Property Owner Contact

4.1.1.1 Introduction

Brush Control, Line Clearing, and Property Owner Contact are three distinct yet closely related activities in the Vegetation Management Program.

Brush control refers to managing the growth of trees and shrubs on the right of way floor so that they do not grow to a height that would cause an outage to the transmission line. Funds are used to maintain access along the right of way for inspection, maintenance activities and emergency response. A number of different methods are used to manage rights of way vegetation, including selective herbicide application, species management, and mechanical clearing.

Line clearing refers to the activity of assessing and removing "Danger Trees" that grow at the side of the right of way or on the right of way to protect water courses or act as visual screens. Danger trees are trees of questionable soundness and health, which could fall and contact line conductors, causing an outage. In addition, line clearing may include the removal or trimming of large trees in urban areas, which if removed are in some cases replaced with compatible vegetation to address local and environmental concerns. Line clearing is carried out as a separate activity from brush control, as it requires a higher level of skill to identify and remove trees that may jeopardize the security of a transmission line.

The activities of brush control and line clearing must comply with the new requirements of the NERC Vegetation Management Standard that came into effect during 2006. These requirements followed the August 14, 2003 northeast blackout in which tree contact with energized conductors was found to be one of the significant causes. Since that time, the management of vegetation has received added regulation to prevent blackout reoccurrences.

Property Owner Contact is undertaken to acquire approval for access onto private property, obtain input concerning any restrictions and environmental concerns, and to communicate maintenance plans to property owners. During this activity, job planning and project layouts are completed, a detailed scope of work is prepared, and approvals are obtained from stakeholders such as property owners, municipalities, and the Ministry of Natural Resources.

4.1.1.2 Investment Plan

Brush control, line clearing, and property owner contact activities are generally set on a cyclical basis as rights of ways are maintained approximately every 7 years on average. This cycle is considered to be appropriate for the system, as it is cost-effective and provides a sustainable level of reliability and is generally consistent with past accomplishment.

4.1.1.3 Summary of Expenditures

The spending requirements for the brush control for test years 2011 and 2012 are $16.2 million and $16.7 million respectively. The test year 2011 spending is 2.5% more than for the bridge year 2010, and the test year 2012 is 3.1% more than the 2011 spending. The primary reason for these increases is attributed to escalation.

The spending requirements for line clearing for test years 2011 and 2012 are $4.4 million and $4.5 million respectively. The test year 2011 spending is 2.3% greater the bridge year 2010 spending, and the test year 2012 spending is 2.3% greater than 2011. The primary reason for the increase is attributed to escalation. Spending in line clearing can vary significantly from one year to the next depending on the complexity of the work that may be required, e.g. urban vs rural. The increase in the test years is in part attributed to more complex projects than historic, as well as a slight increase in accomplishment and escalation.

For Property Owner Contact, the 2011 and 2012 spending is $1.2 million and $1.3 million respectively. These amounts are reasonably consistent with historic expenditures.

The proposed levels are required to mitigate the risk of tree related outages to the transmission network and to avoid such events as the August 14, 2003 northeast blackout in which tree contact with energized conductors was found to be one of the significant contributors to the blackout. Since that time, the management of vegetation has received added regulation and heightened awareness to prevent such reoccurrences. The current proposed program meets the requirements of the NERC regulations, however should the program be reduced, there is an increased risk of tree contacts resulting in outages and regulatory intervention with potential fines, as well as a reduction in customer and system reliability. The vegetation management program has been designed to maintain reliability as well as minimizing life cycle costs. Reductions would result in an increase in life cycle costs, and reduced efficiencies attributed to higher volumes of trees and brush to be treated, as a result of less frequent line clearing and brush control.

4.1.2 Condition Patrols

4.1.2.1 Introduction

Condition patrols are conducted along rights of way to identify, assess and document potential risks to the security of a line, as well as to obtain information concerning the condition of the vegetation on rights of way. Patrols provide experienced staff the opportunity to assess the condition of the rights of way and determine the optimum time to schedule the next maintenance activities. Data is captured on vegetation growth rates, quantities of danger trees, species of brush and trees, and clearance conditions. This data is then used as the primary input for setting line clearing and brush control schedules. This is the accepted practice for controlling vegetation through the utility industry. As well, trees that pose a threat to the reliability of the electrical system are removed.

A new pending regulatory requirement stipulated by NERC will require annual patrols to identify emerging issues and clearance violations. Patrols of this type for vegetation assessment are not part of Hydro One's current practices.

4.1.2.2 Investment Plan

Patrols are carried out near the mid-cycle of right of way work (i.e. brush control and line clearing) as determined by historical accomplishment data and forecasted future maintenance dates. A mid-cycle condition patrol is considered optimal as it strikes a balance between having to forecast too much future growth in order to schedule the next set of maintenance activities and the risk of leaving excessive growth on the system too long.

Analysis of condition patrol data provides an indication of growth rates, clearances, and other vegetation conditions that will need to be addressed. If this analysis indicates particularly poor conditions on a right of way, then brush control, line clearing, and property owner contact will be brought forward on the schedule. If the opposite occurs, and a right of way is found to be in good condition despite not having been maintained for a lengthy period of time, then line clearing and brush control are pushed back on the schedule to make room for higher priority work.

As well, the upcoming revision to the NERC Vegetation Management standard will require that Hydro One Transmission patrol its lines on an annual frequency, which is not part of the current maintenance program, but has been added to the test year's maintenance plans.

4.1.2.3 Summary of Expenditures

The proposed 2011 and 2012 spending is \$1.5 million and \$1.6 million respectively. The test year 2011 spending is 15.4% greater than the 2010 bridge year. The reason for the increase is attributed to the new NERC regulatory requirement to patrol circuits on an annual basis. Test year 2012 spending is 6.6% more than the 2011 spending. The primary reason for the increase is attributed to complete phasing in of the new NERC requirements and escalation.

Reductions in this program will have adverse impacts on the efficiencies of the larger program, i.e., brush control and line clearing, as job plans will not be of a quality to plan work efficiently. As well, some condition information will not be collected and some trees that are at risk of falling and causing an outage will not be removed, thereby increasing system and customer reliability risks.

4.1.3 Demand Maintenance

4.1.3.1 Introduction

Demand maintenance work is required to address vegetation management issues that cannot wait until the next scheduled maintenance activity (e.g. line clearing or brush control). Issues addressed through demand work arise as a result of problems identified by the public, storm damage, urban development, tree caused outages and problems identified during annual and condition patrols.

4.1.3.2 Investment Plan

The primary information required for assessing program needs are demand expenditures from recent historic years, explanations and data related to variances in particular years (e.g. impact of major storms), along with knowledge of any existing or projected factors that would impact future expenditures.

4.1.3.3 Summary of Expenditures

The proposed 2011 and 2012 spending is $1.4 million for each year. These amounts are based on historic expenditures under this category.

4.1.4 <u>Grounds Maintenance</u>

4.1.4.1 Introduction

Grounds maintenance funds activities on transmission rights of ways such as grass cutting in urban areas, security patrols, maintenance of access barriers and fences, snow removal, and garbage removal.

4.1.4.2 Investment Plan

Maintenance decisions are made considering regulatory requirements, local by-laws, and customer requirements. For example, grass cutting must be carried out during the growing season to comply with local by-laws with respect to weed control. Generally, grounds maintenance requirements are consistent from one year to the next and as a result forecast expenditures are largely based on historic expenditure levels.

4.1.4.3 Summary of Expenditures

Proposed spending for 2011 and 2012 is $ 2.7 million and $2.8 million respectively. These amounts are aligned with historic expenditures.

Reductions in this program would result in an increase in complaints by the public and municipalities, as garbage could not be removed in a timely manner, or grass cut to meet municipal by-laws. This may result in fines and more costly response of an unplanned nature, as compared to planned.

4.2 Overhead Lines Program

The overhead lines program provides funding to maintain the reliability of transmission lines, address safety issues, meet regulatory and legal requirements, and ensure the financial long term viability of the overhead lines system. The program includes funding for activities such as overhead lines inspections to identify defects, emergency response, and the gathering of information that will enable funding to be allocated on a priority basis to maximize the life of the lines assets and maintain performance. The program also provides for repair or replacement of defective equipment and components.

The Overhead Lines Program is divided into three programs: preventive maintenance and asset condition assessment; trouble calls; and planned corrective maintenance and projects. The proposed 2011 and 2012 funding along with the bridge and historic spending levels for each of the categories is provided in Table 6 below.

Table 6

Overhead Line Programs ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Preventative Maintenance & Asset Condition Assessment	9.4	8.5	9.7	9.7	9.8	10.1
Demand Maintenance	3.3	4.3	4.4	4.2	4.4	4.4
Planned Corrective Maintenance & Projects	3.8	6.2	5.3	4.0	6.0	8.5
Total	**16.5**	**19.0**	**19.4**	**17.9**	**20.2**	**23.0**

4.2.1 Preventative Maintenance & Asset Condition Assessment

4.2.1.1 Introduction

Preventative Maintenance and Asset Condition Assessment encompasses a number of activities that are undertaken to keep lines assets in working order and to identify conditions that may impact their operation and reliability, as well as acquiring condition information needed to identify components in need of replacement or refurbishment. The activities include foot, helicopter and thermovision patrols, insulator washing and switch maintenance, and the assessment of various transmission line components that include poles, steel towers, insulators, conductors, shieldwires, anchors, and guys.

4.2.1.2 Investment Plan

Preventative Maintenance

Preventative maintenance includes an annual helicopter patrol and in areas where flight restrictions exist, lines are patrolled on foot. The patrols identify any public safety issues and defects that may jeopardize customer and system reliability.

Thermovision patrols are carried out with the purpose of identifying condition “hot spots” (e.g. loose connections) that put line components at risk of failure and that are not visible to the naked eye. Predicting imminent failures has tremendous reliability benefits and as a result, thermovision patrols are conducted on an average 3-year cycle. More critical lines such as those on the 500 kV system, inter-ties (i.e. inter-provincial or international lines), and those servicing critical generating plants are conducted on an annual basis.

Furthermore, preventative maintenance includes insulator washing in areas where salt contamination has been identified as a problem, inspections of aviation lighting on towers, switch maintenance and climbing inspections.

Asset Condition Assessment

Asset condition assessment includes a number of activities that have been designed to provide the information needed to manage the transmission system and to identify defects that jeopardize public and worker safety and the reliability of the system. Specific activities include:

- Steel tower assessments examine tower components above ground and at the ground line. Assessments are carried out on those lines that show signs of noticeable corrosion and that have structures in swamps, standing water or are located in known corrosive areas.
- Shieldwire and conductor testing targets conductors that have been in service for more than 50 years and shieldwires in service for more than 30 years. Once tested, those conductors and shieldwires determined to be at end of life, and pose a risk to the reliability of the system as well as a hazard to the public and employees, are scheduled for replacement under the appropriate Capital programs.
- Insulator testing is conducted on specific line sections where annual assessments of reliability performance or patrol observations suggest insulator conditions may be deteriorating.

- Periodic field survey of electrical clearances of transmission lines are required to ensure that clearances are adequate for current operating conditions, or in response to proposed increases in operating conditions.
- Wood pole line assessments include detailed helicopter inspections of the condition of crossarms and pole tops, and individual pole testing to evaluate the soundness of the wood near the ground line. The lines selected for detailed helicopter inspections are identified based on accessibility, pole ages, and reliability information. Ground inspections target about 3,000 to 4,000 structures a year.

Wherever possible, condition assessment activities are scheduled in a complementary fashion such that cyclical and non-cyclical needs are addressed as efficiently as possible. For example, a line section that requires pole and crossarm assessments will be scheduled for a detailed helicopter patrol and pole testing such that both assessments are met and the need for the separate cyclical helicopter patrol is avoided.

4.2.1.3 Summary of Expenditures

Proposed spending for preventative maintenance and asset condition assessment for 2011 and 2012 is $9.8 million and $10.1 million, respectively. The test year 2011 spending is 1.0% more than for the bridge year 2010 and the test year 2012 is 3.1% more than the 2011 spending. The primary reason for these increases is attributed to cost escalation. Over the last four years problems have been identified on certain types of polymeric insulators, conductors damaged by aeolian (wind induced) vibration, wood pole arms and the 500 kV lines north of Barrie. In order to manage these issues and to limit the number of component failures, continued inspections and condition assessments are required.

Reductions in this program will result in added reliability risks and failures that could impact public safety. The transmission system is located in the public domain and a number of the maintenance activities have been designed to identify possible failures before they occur. Failure of insulators, wood arms and conductors will bring energized conductor to the ground creating a hazardous situation for the public.

As well, asset condition information is needed to manage end of life replacements and without adequate condition information, there will be diminished effectiveness in replacement programs with added failures, and increased reliability and safety risks.

4.2.2 Demand Maintenance

4.2.2.1 Introduction

Activities in this program are needed to respond to emerging problems and to restore power should it become necessary. Lightning storms, ice build up on lines and high winds can result in the failure of transmission line components, which requires immediate response and repair. This program also provides funds to address problems identified during line patrols that need a short term response to prevent a potential outage or to address a serious safety issue. .

4.2.2.2 Investment Plan

This program is reactive in nature and varies due to weather, equipment deterioration and equipment failures. Funding is based on historic volumes of work and expenditures.

4.2.2.3 Summary of Expenditures

The proposed 2011 and 2012 spending is $4.4 million each year and is consistent with historic expenditures.

4.2.3 Planned Corrective Maintenance and Projects

4.2.3.1 Introduction

Planned Corrective Maintenance and Projects includes funds for minor corrective work (e.g. ground wire replacements, clearance corrections, planned defect corrections) and larger scale projects needed to address wide spread design, manufacturing, or condition deficiencies and safety issues. As well, this program includes funds for technical support to resolve reliability problems with transmission line assets.

4.2.3.2 Investment Plan

Planned corrective maintenance activities and projects are developed using the data collected through the patrols and asset condition assessment activities discussed in Section 4.2.1.2 of this Exhibit, as well as information on equipment reliability performance, and findings of expert analysis. Defects corrected under this OM&A program may include loose guy wires, broken strands of conductor, damaged insulator strings, dislodged tower members, and broken ground wire.

Other corrective maintenance activities include tower anchor bolt security to deter vandalism and the installation of anti-climbing barriers to prevent public access to towers. Maintenance of this type is targeted to specific locations that have been identified as high risk.

Issues requiring more specific actions are addressed separately through targeted projects. One such issue has been identified on the 500 kV lines between Barrie and Timmins that form the backbone of the North-South transmission network. Inspections show that the support guys, rock anchors and the foundations of the guyed "V" towers built in the early 1960's are severely deteriorated. Poor footing soil conditions and winter frost action have resulted in damaged members and loose guys. Correction of these structural problems is essential to maintain the reliability of this vital link. Another significant project involves corrective action to address deteriorated and worn U-bolts that support insulator strings and conductor on the 500 kV lines between Barrie and Sudbury. This problem stems from a metallurgic deficiency in the metal and must be rectified to maintain integrity of this important line.

Furthermore, conductor damage has been discovered on several lines in southwestern Ontario stemming from wind induced vibration. The problem is similar to the lines between London and Sudbury that were identified in EB-2008-0272, Exhibit C1, Tab 2, Schedule 2, page 45. Remedial measures are needed to prevent further damage and to make repairs where required.

4.2.3.3 Summary of Expenditures

The test year spending requirement for this program is $6.0 million in 2011 and $8.5 million in 2012. The test year 2011 spending is 50% more than the bridge year 2010 and the test year 2012 is about 42% greater than the 2011 spending. The primary reason for these increases is attributed to problems as identified above on the 500 kV lines and the conductor damage as a result of aeolian vibration.

Reductions in this program will result in defects remaining on the system for extended periods of time and thereby increasing the likelihood of failures resulting in increased reliability risks and public safety issues. For example, deferring repairs on the 500 kV lines would increase the likelihood of failures, as occurred during 2009 when a u-bolt supporting the insulators broke, resulting in a circuit outage.

4.3 Underground Cable Programs

Hydro One Transmission's High Voltage Underground ("HVUG") Cable system consists of 115 kV and 230 kV cables. Underground cables are located in the urban centers of Toronto, Hamilton and Ottawa, with short sections in London, Sarnia, Picton, Windsor and Thunder Bay.

This program reduces the risk of cable equipment failure which can seriously impact service and reliability to a large number of urban areas. The activities within this program ensure that corrective action is taken when component failure is imminent or when defects are discovered during routine inspections. Timely response to external requests for a cable locate is included in these activities. Preventative Maintenance activities such as cable diagnostics are also included as part of this program. Since most of the underground facilities are not visible or easily accessible, these activities provide an indication of the state of the cable components.

The proposed funding levels for 2011 and 2012 along with the spending levels for the bridge and historic years are provided in Table 7 below.

Table 7

Underground Cable Programs ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Cable Locates	0.3	0.3	0.4	0.4	0.4	0.4
Preventative Maintenance	1.5	1.1	1.3	1.3	1.4	1.4
Corrective Maintenance	1.6	2.3	2.7	1.8	2.0	2.1
Total	**3.5**	**3.7**	**4.4**	**3.5**	**3.8**	**4.0**

4.3.1 Cable Locates

4.3.1.1 Introduction

This program provides funding to respond to external requests for locating Hydro One Transmission's underground cable facilities. Responding to these requests is in everyone's best interest as anyone excavating near a cable may cause damage to these costly assets and harm themselves or members of the public. Hydro One Transmission uses the services of "Ontario One Call" to field requests for cable locates and then completes the field identification as required.

4.3.1.2 Investment Plan

The program is driven by external demand and the costs are not recovered by end use charges, which is consistent with the practice of other utilities. The "no fee" policy is in place to encourage contractors to make use of the service and avoid costly and hazardous situations. Historic expenditures and numbers of requests are analyzed and used to forecast future expenditures.

4.3.1.3 Summary of Expenditures

The proposed 2011 and 2012 spending is $0.4 million for each year, which is identical to the bridge year.

Reductions in this program present unacceptable risk to contractors and the public digging in and around our high voltage cables.

4.3.2 Preventative Maintenance

4.3.2.1 Introduction

Underground cables are made of a number of components and subsystems, the condition of which can deteriorate during the cables' service life. Preventative maintenance activities are aimed at determining cable condition and ensuring system reliability.

4.3.2.2 Investment Plan

Underground cable condition information is determined through a number of activities as listed below.

- Condition patrols focus on underground cables and their auxiliary systems such as the oil pumping plants and cathodic rectifiers.
- Cable pipe polarization spot checks are required to monitor the corrosion protection that is installed on the cable pipes.
- Cable pipe corrosion surveys are conducted on the protective steel pipes that protect many of Hydro One Transmission's cables.

- Oil testing and analysis is carried out to determine if there is any accumulation of dissolved gases in the insulating oil, which may be a sign of deteriorating condition.
- Route patrols at ground level are conducted to look for any unknown excavations near the cables or any evidence of oil leaks that would indicate a breach in the piping system.
- Jacket tests are conducted on cables in the system that are not protected by a steel pipe. These include oil filled cables protected by a metallic sheath and an outer PVC jacket.
- Infrared tests are conducted on cable components called potheads, which mark the transition of a conductor from overhead to underground, to determine if the materials that make up the pothead are exceeding thermal limits.
- Vault inspections are carried out on cable systems having splice locations that are enclosed in a concrete vault.
- Cable Diagnostic activities are carried out on the cable systems to assess condition and maintain reliability. Tests include oil leak detection, sheath current measurements and laboratory insulation assessment.

The large majority of preventative maintenance activities are cyclical in nature (e.g. route patrols are conducted twice per month) and expenditure levels are set to maintain these cycles. However, condition data and reliability performance may drive the need to adjust the frequency of maintenance activities for specific cables that may be a source of concern.

4.3.2.3 Summary of Expenditures

The preventative maintenance spending for 2011 and 2012 is $1.4 million for each year. Spending during the test years is aligned with historic expenditures.

Any reductions to the proposed plan would have financial, reliability, environmental and safety implications. Preventative maintenance programs have been instrumental in the past in identifying emerging issues within the cable system and permitting repairs to be made, thereby avoiding high impact failures. Failures result in unplanned circuit outages, potential explosive situations with safety implications, as well as oil spills to the environment. Such events are very expensive, disruptive to the network and reduce the service life of the cables which are very expensive to replace, as well as putting at risk the supply of power to the downtown areas of Toronto, Hamilton and Ottawa.

4.3.3 Corrective Maintenance

4.3.3.1 Introduction

Corrective maintenance work includes repairs of defects discovered through preventative maintenance activities, and may involve repairing oil leaks, coating of cable terminations, repairing of cable sheath and pipe coating and topping up oil levels. These repairs are essential to keep the cables and their associated components in a reliable state of operation.

4.3.3.2 Investment Plan

The activities included under corrective maintenance are primarily reactionary and demand in nature, but also include planned corrective where problems have arisen and there is adequate time to correct defects without significantly jeopardizing reliability and safety.

Demand elements of the program include responding to oil leak alarms by topping up oil reservoirs that feed oil filled cables. Leak locating and repair of same, as well as clean up of site and remediation of contaminated soil.

Planned repairs include removal and replacement of oil that has unacceptable concentrations of harmful gases, sheath repairs that have been damaged through corrosion and adjustment and repairs to monitoring equipment.

4.3.3.3 Summary of Expenditures

Proposed spending for corrective maintenance for 2011 is $2.0 million and for 2012 is $2.1 million. The test year 2011 spending is 11% more than for the bridge year 2010 and the test year 2012 is 5% more than the 2011 spending. The primary reason for the increase is an update of demand costs to more closely align with historic needs.

Reductions in this program will hamper the ability to repair defects which will shorten the life of these critical assets and will cause premature deterioration leading to oil leaks, insulator damage and the risk of loss of supply to the downtown areas in major centres of Ontario.

5.0 ENGINEERING AND ENVIRONMENTAL SUPPORT

5.1 Introduction

This program funds support activities, including management of records and drawings, CAD drawing support, data base management and provision of specific technical information (e.g. preliminary costing of potential investments for selecting the most cost-effective alternative). In addition, this program funds technical support including specialized studies, outage assessments conducted by the IESO, event investigation and incidents response and external consulting services that provide technical expertise not available within Hydro One Transmission.

All of this work will be impacted by the increase in capital expenditures as these projects will require drawings, and in-turn increased drawing maintenance. The technical support and specialized studies are completed on an ad-hoc basis to aid in the decision making process for capital investments.

Required funding for the test years, along with the spending levels for the bridge and historic years are provided in Table 8.

Table 8
Engineering and Environmental Support OM&A ($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2007	2008	2009	2010	2011	2012
Engineering and Environmental Support	8.9	10.1	12.5	11.5	11.0	11.8

5.2 Investment Plan

This program is strictly demand work and the level of funding is based on historical trends and adjusted to incorporate the changes in the planned transmission work programs.

The historical level of usage is reviewed annually to assess if the historical spending level needs to be adjusted to recognize any incremental requirements related to the magnitude and scope of the planned transmission work program.

5.3 Summary of Expenditures

The spending requirements for Engineering and Environmental Support are $11.0 million for 2011 and $11.8 million for 2012. Projected spending is aligned with historic expenditures and it is expected that the increasing capital work program can be managed within the historic levels of spending.

The level of funding requested will ensure that the investment decisions made are based on accurate information and that customer, legal, environmental and regulatory requirements are met.

DEVELOPMENT OM&A

INTRODUCTION

Development OM&A provides the funding for work in the following key areas:

- Research, Development & Demonstration
  These investments are undertaken for projects to investigate the use of new technologies and/or practices that, if proven feasible, may be utilized by Hydro One Transmission to improve sustainment and/or development of its system.
- Standards Development
  Primarily these investments are to develop new and/or update existing standards to meet any mandatory standards or regulatory requirements including planning, design, and construction.
- Smart Zone Development
  These projects focus on investments that will facilitate greater integration of renewable energy generation in the province and provide enhanced control and protection of the transmission system resulting in improved reliability.
- Development Work for Major Transmission Projects
  Under these investments funding is provided for development work (planning, scoping, pre-engineering estimating, environmental assessments and approvals etc) for projects outlined in the letter from the Minister of Energy and Infrastructure, dated September 21, 2009 to proceed with planning, development and implementation of specific transmission projects (Schedule A) and upgrades to enable renewable energy generation (Schedule B). The cost associated with development work will be captured in the Long Term Project Development OM&A account as discussed in Exhibit F1, Tab 1, Schedule 2.

2.0 DISCUSSION

Development OM&A included in revenue requirement covers expenditures of three specific programs: Research, Development and Demonstration ("RD&D"), Standards Development, and Smart Zone Development. Expenditures relating to pre-engineering work regarding transmission projects outlined in the Minister's letter of September 21, 2009 will be captured in a variance deferral account. The proposed expenditure levels for Development OM&A including pre-engineering work for specific transmission projects are shown in Table 1 below for historical, bridge and test years.

Table 1
Summary of Development OM&A ($ Million)

Description	Historic			Bridge	Test	Test
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Research, Development and Demonstration	4.4	3.0	6.0	6.3	6.4	6.6
Standards Development	4.0	6.2	7.9	8.7	7.8	8.3
Smart Zone Development*				4.0	4.0	4.0
Total	**8.4**	**9.2**	**14.0**	**19.0**	**18.2**	**18.9**
Development Work for Transmission Projects	0	0	1.9	8.2	35.7	46.7

*New development initative

The increased spending levels in the test years are required to fund innovation strategies related to Smart Zone development that provide value to Hydro One customers through transmission infrastructure enhancement; and develop/update technical transmission standards in response to new technologies and new regulatory reliability/compliance requirements. There is significant new Standards development required in 2009 and beyond to accommodate increased distributed generation installations which impact the transmission stations, system monitoring, along with, protection & control, telecommunication and data processing infrastructure.

Reduced funding would require deferment of some or all enabling transmission work associated with distributed generation projects, and increase the risk of not meeting legal, regulatory and work execution needs due to the unavailability of required standards. Opportunities to reduce future costs through the use of emerging technologies would be missed.

2.1 Research, Development and Demonstration

The objectives of the RD&D Program are to assess and evaluate the feasibility of emerging technologies and to enable the implementation of new tools, equipment and practices that result in efficient and effective utilization of the transmission system and its components. RD&D projects intend to provide information that will permit Hydro One Networks to make informative investment decisions that improve system performance and meet the needs of Ontario in a responsible and timely manner. This will be achieved through:

- Leveraged investments in assessing emerging technologies
- Pilot projects, if necessary, to test new technology in an operational environment before widespread deployment
- Improvements in design, maintenance and operations practices
- Development of better risk assessment tools
- Partnerships with universities and centres of excellence

The RD&D program provides the funding to monitor, assess, and evaluate the benefits and feasibility of emerging technologies to enable the implementation of new tools and methods. Hydro One Transmission monitors emerging technologies mainly through its participation in industry interest groups to pool knowledge. For example, two such interest groups are CEA Technologies Inc. (“CEATI”) and Electric Power Research Institute (“EPRI”). This allows for Hydro One Transmission’s investments to be leveraged by jointly funding projects with other utilities and having broader access to expertise that has similar interests or challenges. For example, Hydro One is currently working with several North American electric utilities through EPRI in influencing the development of an effective smart grid and Critical Infrastructure and Cyber Security related standards.

The RD&D program also funds implementation of pilot projects to confirm viability of new technologies and products before their widespread deployment within Hydro One. This allows the identification of potential risks associated with application of these new technologies and their integration into Hydro One Transmission’s system.

The 2003 blackout resulted in several recommendations. One of the actions was to explore Wide Area Monitoring of events and/or system conditions that may result in cascading outages. Working in conjunction with other utilities in North America as well as the U.S. Department of Energy (DOE) and NERC, Hydro One is working with University of Western Ontario in assessing the effective deployment strategy of Phasor Monitors.

There are also RD&D projects aimed at improving design, operation and maintenance practices and/or to develop better risk assessment tools. An example of such a project is the Dynamic Transformer Rating (“DTR”) project. It is expected that completion of this project will enable Hydro One to establish real time ratings of transformer assets based on real time asset operating and ambient conditions without compromising their life at critical peak load times.

This program also funds partnerships with universities to support the power system options in electrical engineering at various universities and to make students available to Hydro One Transmission for research-oriented work. Hydro One is committed to training undergraduate and graduate students as potential future employees for the company. Funding is also leveraged with Natural Sciences & Engineering Research Council (NSERC) grants awarded to research associates. Hydro One Transmission also has a commitment with the Ontario Centres of Excellence which is a not-for-profit organization that brokers industry/academic research partnerships in Ontario to complete RD&D initiatives for the benefit of the province as well as taking research discoveries to the commercial market place.

2.2 Standards Development

The Standards Development Program covers the development of new standards and the review/revision of existing technical transmission standards. These developments are in response to technological advancements (e.g. new relay technology), and changes to regulatory/compliance requirements (e.g. distributed generation) and standards as set by the revised Transmission System Code, and regulatory/reliability standards organizations such as North American Electric Reliability Corporation (“NERC”), Federal Energy Regulatory Commission (“FERC”) and Northeast Power Coordinating Council (“NPCC”). Others are driven by public and worker safety, equipment obsolescence, and changes in construction and work methods. Hydro One Transmission monitors and influences emerging industry standards and requirements for new standards mainly through its participation in Canadian Standards Association (“CSA”), International Electro-technical Commission (“IEC”) and the Institute of Electrical and Electronics Engineers (“IEEE”) working groups. Hydro One Transmission recently participated with CEATI North American utility consortium and completed a set of Fire Protection guidelines for High Voltage Transmission Stations. This guide is providing significant input to the IEEE Standards and Guide that is currently under development. Another example will be development and adoption of harmonic emissions related standards both at IEC and CSA from household appliances through projects sponsored with CEATI.

2.3 Smart Zone Development

Development OM&A expenditures also fund long-term innovation strategies relating to Smart Zone development. These strategies offer value to Hydro One customers through improvements in metering tools, protection and control systems as well as enhancing transmission infrastructure to connect additional renewable energy generation as called upon by the *Green Energy and Green Economy Act, 2009*. (GEGEA)

Many of these innovation efforts are facilitated through Hydro One's Smart Zone located in the Owen Sound area, which tests and proves the feasibility of new emerging technologies that will permit Hydro One to implement smart grid solutions in a proactive manner as asset solutions and replacement strategies are decided.

Investments for work associated with Hydro One's Smart Zone are further discussed in Exhibit D1, Tab 3, Schedule 3.

Smart Zone projects are essential to Hydro One's investment in innovation. Smart Zone development also supports Hydro One's commitment to Excellence by seeking reliability improvements in the delivery of electricity, reducing durations of outages and improving outage response rates.

Smart Zone projects aim to improve the reliability and quality of supply to customers or improve performance monitoring for the transmission system. One of these projects includes piloting new technologies and next generation IED (intelligent electronic devices) for station equipment condition diagnostics. These diagnostics will allow better understanding of asset condition and will become a key element to improve maintenance programs (e.g. optimized maintenance schedule and prioritized equipment refresh). In another project, Hydro One is working together with other LDCs, Ontario Centre of Excellence ("OCE"), University of Waterloo and University of Western Ontario to examine the implications and maximization of large scale integration of solar photovoltaics ("PV") on the Hydro One network .

3.0 DEVELOPMENT WORK TO SUPPORT THE ONTARIO GOVERNMENT'S GREEN ENERGY AND GREEN ECONOMY ACT

In May 2009, the Ontario Government passed the GEGEA which provides a framework for developing renewable generation in Ontario; including the introduction of the Feed-In-Tariff (FIT) program. For further details refer to Exhibit A, Tab 11, Schedule 4.

In a letter dated September 21, 2009, the Minister of Energy and Infrastructure requested Hydro One to immediately proceed with the planning, development and implementation of transmission projects (Schedule A) and upgrades to enable distribution system connected generation (Schedule B). In support of the Ontario Government's initiative, Hydro One Transmission has initiated Development work for some of the specifically identified projects.

As discussed in Exhibit F1, Tab 2, Schedule 1, Hydro One is requesting recovery of the 2009 OM&A development costs of $1.9 million ($2 million with interest). As discussed in Exhibit F1, Tab 1, Schedule 2, Hydro One is not requesting recovery of the other OM&A costs included in this deferral account at this time. Please refer to Exhibit A, Tab 11, Schedule 4 for further discussion of future development cost recovery considerations.

3.1 Development Work Project Details

The Ontario Government transmission projects (Schedule A) and enabling distributed generation projects (Schedule B) include major transmission projects that will require extensive planning and pre-engineering work. In order to satisfy the proposed schedule, preliminary work will need to commence in advance. The development work includes: collecting initial data from internal sources; initiating work to obtain approvals; conducting feasibility studies; performing preliminary engineering and cost estimates to identify and assess alternatives; undertaking external stakeholder consultations; and submitting applications to obtain Environmental Assessment (“EA”) and Section 92 ‘Leave to Construct’ approvals. It will also entail working with the OPA and other agencies, to ensure that the pre-engineering work for the identified projects is carried out in a timely manner and as required by statutes and regulations.

Performing the development work is an important strategy in meeting the GEGEA policy objectives as it provides a range of options that can be committed at a later date and minimizes the delays in major transmission projects. Initiating the work required for lengthy external approvals will greatly reduce the required lead times once it is decided to commit a major project. Lack of funding for this development work would lose the opportunity to reduce long lead times and would not provide the necessary flexibility to incorporate renewable generation in a timely fashion..

The OPA is developing the Economic Connection Test (ECT) model, the results of which will identify where new transmission is required to connect those Feed-in-Tariff applications that have not been awarded FIT contracts due to a lack of available transmission capacity. Based on the Minister’s letter, Hydro One began preliminary work on 8 higher priority projects. The development work spending required to support all the Ontario Government's instructed Transmission projects are provided in Table 1 below.

[

Table 1: Summary of Development Work for Government Instruction Projects

Item #	Investment Description (Item # as per Schedule A) [1]	EA Status	Section 92 Status	Cash Flow ($ Millions)						
				Historical			Bridge	Test	Test	Total Cost[2]
				2007	2008	2009	2010	2011	2012	
1	East-West Tie Expansion (Item #1)	Required	Required	0	0	0	0.7	4.1	3.0	12.0
2	North-South Transmission Expansion (Items #2/3)	Required	Required	0	0	0.1	1.5	4.5	3.0	18.5
3	Algoma x Sudbury Transmission Expansion (Item #4)	Not Required	Required	0	0	0	0.6	2.0	3.0	5.5
4	Transmission Reinforcement West of London (Item #5)	Required	Required	0	0	0	0.7	9.0	10.0	22.5
5	Bowmanville SS x GTA (Item #6)	TBD	Required	0	0	0.4	0	0	0	11.5
6	Goderich Area Enabler (Item #7)	Required	Required	0	0	0.1	0.4	1.0	2.5	5.0
7	Manitoulin Island Enabler (Item #8)	Required	Required	0	0	0.1	0.5	1.0	3.0	7.5
8	Huron South Enabler (Item #9)	Required	Required	0	0	0	0	0	0.5	1.0
9	Pembroke Area Enabler (Item #10)	Required	Required	0	0	0	0	1.5	3.0	8.0
10	Parry Sound Enabler (Item #11)	Required	Required	0	0	0	0	0.5	2.5	5.5
11	North Bay Enabler (Item #12)	Required	Required	0	0	0	0	0.5	2.2	5.5
12	Thunder Bay Enabler (Item #13)	Required	Required	0	0	0	0	1.0	4.0	12.0
13	Northwest Transmission Reinforcement (Item #14)	Required	Required	0	0	1.2	3.0	10.5	7.0	21.7
14	St. Lawrence TS x Merivale TS (Cornwall x Ottawa) (Item #15)	Required	Required	0	0	0	0	0	0.5	1.0
15	Selby Junction x Belleville TS (Item #16)	Required	Required	0	0	0	0	0	0.5	1.0
16	Chenaux TS x Galetta Junction (Item #17)	Required	Required	0	0	0	0	0	0.5	1.0
17	Sudbury North - Pinard TS x Hanmer TS (Item #18)	Required	Required	0	0	0	0	0.1	1.5	5.0
18	Longwood TS x Middleport TS (Item #19)	Required	Required	0	0	0	0	0	0	9.5
19	Kenora x Thunder Bay Transmission Expansion (Item #20)	Required	Required	0	0	0	0	0	0	5.0
20	Toronto Area Station Upgrades for Short Circuit Capability (Item #3 – Schedule B)	Not Required	Not Required	0	0	0	0.8	0	0	0.8
	Total			**0.0**	**0.0**	**1.9**	**8.2**	**35.7**	**46.7**	**159.5**

Note 1: These investments are equivalent to the projects (Item #) as indicated in Schedule A of the government letter to Hydro One dated September 21, 2009.
Note 2: "***Total***" costs include cash flows, if any, in years before 2011 and after 2012.

Note 3: There are 11 more projects that were approved as part of the IPSP and Other Long Term Projects OM&A deferral account in the EB-2008-0272 proceeding. These projects are:

Transmission Line – Thunder Bay Area: Birch x Lakehead
Major Transmission – Manitoba Border x Southern Ontario
Bruce Peninsula Enabler Line
New 500/230kV Oshawa Area TS
Northern York Transmission Reinforcement
Kitchener-Waterloo-Cambridge-Guelph (“KWCG”) Transmission Reinforcement
230kV Transmission Line – Parkway x Richmond Hill
230kV Transmission Line – Richview x Manby
New Supply to City of Toronto
115kV Leaside and Manby TS – Uprate Short Circuit Capability
Milton Transformer Station

OPERATIONS OM&A

1.0 INTRODUCTION

The Operations OM&A program funds the operations function, which manages the transmission assets in real time on a continuous basis. This includes monitoring and controlling the transmission assets, coordinating and scheduling planned maintenance outages, and monitoring and reporting on the performance of the transmission system. These expenditures fund the operation of Hydro One Transmission's system consistent with good utility practice and within the requirements established by the reliability authorities, operating agreements and the market rules.

Operations OM&A also includes initiatives to support environmental, health and safety activities that are required to meet legal obligations and due diligence requirements and also the Company's program for managing its relationship with its large customers and generators.

2.0 DISCUSSION

Operational activities associated with the transmission system are carried out centrally at the Ontario Grid Control Centre ("OGCC"). The OGCC is a shared facility which allows central operations of the transmission and distribution systems and is backed up by facilities located at a separate site. Back-up operating facilities are provided at a separate facility as required to meet North American Electricity Reliability Corporation ("NERC") standards and is consistent with good utility practice.

The 2011 and 2012 test year costs for transmission operations at the OGCC is based on the cost allocation methodology proposed by Black And Veatch and accepted by the

Board during the previous two Transmission applications under Proceedings EB-2006-0501 and EB-2008-0272, as discussed further in Exhibit C1, Tab 5, Schedule 1.

The OGCC is the operating authority for Hydro One's transmission system including connections to other neighbouring transmission systems in Canada and the United States. During real-time operations, the OGCC monitors Hydro One Transmission's system and transformer supply stations for correct voltage levels, equipment loading, and equipment ratings and alarms. The OGCC also prepares Utility Work Protection Code documentation including switching orders for transmission planned and forced outages to ensure a safe working environment for employees.

The Operations OM&A program is divided into four categories:

- Operations, which funds the work required to conduct the safe and reliable operation of the transmission system, including the planning and scheduling of transmission outages;
- Operations Support, which provides for the maintenance of the computer tools and systems for the operations function;
- Environment, Health and Safety, which funds programs to support environmental, health and safety activities that are required to meet legal obligations, due diligence requirements and to assist in achieving corporate health and safety objectives; and
- Contracts and Customer Business Relations, which funds Hydro One's efforts to manage its relationships with transmission-connected industrial customers, LDC's, and transmission-connected generators.

The required funding for the test years, along with the spending levels for the bridge and historic years, are provided in Table 1 for each category.

Table 1
Operations OM&A Allocated to Transmission ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Operations	28.4	29.1	30.2	31.8	32.7	32.8
Operations Support	18.3	16.6	16.6	22.6	24.8	25.9
Environment, Health and Safety	2.9	1.9	1.5	2.6	3.5	4.0
Large Customer & Generator Relations*	4.3	4.1	4.3	5.2	5.3	5.5
Total	**54.0**	**51.7**	**52.6**	**62.1**	**66.3**	**68.2**

*Due to an organization change, in the previous EB-2008-0272 application these costs were included in Shared Services in the Asset Management organization.

- The increase from historic spending levels in Operations is related to staff increases to manage the direct consequence of more Green Energy connected to the system, the indirect consequences such as coordinating more outages for a higher construction work program and succession planning to manage attrition.
- The Operations Support spending shows an increase in the bridge year due to the greater support required for the NMS system and the inclusion of the SCADA HUB site support. The NMS support costs have increased due to a technology change that was required to replace an obsolete system, and this has resulted in an increase in volume of equipment to maintain with increased emphasis on security updates, plus added cost for associated software licensing.
- The Environment, Health and Safety increase from historic spending is the result of several new safety initiatives including the corporate wide program Journey to Zero and ISO 14001/OHSAS 188001 Registration that are targeted to help achieve the Hydro One strategic objective of an injury-free workplace and maintain public safety.
- Large Customer & Generator Relations increase from historic is a result of an increase in work load associated with new generation customers and added customer

interface required to manage the larger work programs, as well as new hires required for succession planning.

The description and details for individual Operations OM&A programs and year-to-year changes are provided below.

3.0 OPERATIONS

This program funds the work required to conduct the safe and reliable operation of the transmission system, including the planning and scheduling of transmission outages. It also includes Network Management System ("NMS") and Network Outage Management System ("NOMS") initiatives designed to increase customer satisfaction by increasing reliability, improving storm restoration times, and improving the execution of the work plan for scheduled outages.

In addition, Hydro One Transmission is registered with NERC as a Transmission Operator. This registration requires that the control room operators be NERC certified as transmission operators. Aside from the initial cost of the NERC certification training there is an on-going mandated requirement to provide continuing education hours annually and provide NERC certification training to new hires.

Operations expenditures increase from historic due to an increase in staff to meet increasing work loads as a result of larger Sustaining and Development capital work programs and the Green Energy related work. This increase in program work will require added outage planning and scheduling, and increased efforts to adequately manage power flows as a result of a greater number of elements being taken out of service. As well, it must be recognized that new staff require 3 years to become qualified, as such it is important to hire in advance of attrition, as has been done to some degree, to ensure the viability of this essential facility to the grid.

The spending requirement for test years 2011 and 2012 are $32.7 million and $32.8 million. These increases over 2010 levels are largely due to escalation. The 2012 spending is essentially identical to 2011, as it is anticipated that a number of higher paid senior staff will retire, thereby reducing the overall spending and largely offsetting escalation.

Operations staff generally have skill sets and experience that make them attractive for promotion into other lines of business. This, as well as the large percentage of employees becoming eligible to retire will result in a higher than average attrition rate. The risk of not proceeding with this plan would result in a critical shortage of skilled resources and the failure of the operating centre to function as required.

4.0 OPERATIONS SUPPORT

This program provides funding for the maintenance of, and minor enhancements to, the operating facilities at the OGCC and back-up centres, as well as services essential to the planning and execution of outages.

The primary operating facilities are the Network Management System (“NMS”), the Network Outage Management System (“NOMS"), the Utility Work Protection Code System, the OGCC Integrated Voice System and the OGCC Emergency Services Information System (“ESIS”). Details concerning each of these systems are provided as part of the discussion on Capital investments in Exhibit D1, Tab 3, Schedule 4.

The essential services to support the day to day operation of the transmission system are described in the sections below.

4.1 Operating Facilities

Operating Facilities maintains all of the facilities required to support the day-to-day operation of the transmission system. These facilities include the various computer systems required for real-time monitoring and control, communications, training, and outage scheduling. Funding for the software licenses, vendor maintenance contracts, consumables and staff labour to support the operating facilities for the OGCC, the back-up centres and the remote operating data collection sites are included in this service.

Operations Support shows a significant increase in the bridge year due to the increased support for the NMS system and enhanced SCADA HUB support. The NMS support costs have increased due to a technology change which required an increase in NMS server count and the associated software licensing. These costs are on-going and are incurred annually.

4.2 Field Switching

Many elements of the transmission system cannot be remotely controlled. In order to fully carry out its accountabilities related to the provision of safe working conditions and reliable operations, the Operations function directs staff in the field to carry out required switching. Field switching primarily supports the maintenance program but may also respond to forced outages and third party requests.

4.3 Load Transfer Studies

Load transfer studies are required to assess the feasibility of electrical configuration changes when maintenance is required on the Hydro One Transmission system. The benefit of carrying out these studies is continued system reliability, reduced impact to customers and safer working environments for Hydro One Transmission employees.

4.4 Maintain Operating Diagrams

Operating diagrams show the interconnectivity of transmission elements and the devices that isolate them from the system.

The operating diagrams are maintained on the following systems:

- The Computer Aided Design Drawings (CADD) system, which contains the transmission diagrams for auxiliary facilities within transmission transformer stations such as dc/ac station service diagrams, air systems, protection and control systems, etc.; and.
- The NMS, which contains all transmission system related drawings used for real time control.

One of the primary uses of operating diagrams is the specification and execution of the Work Protection Code procedures required to provide safe working conditions for maintenance and construction crews. The Development and Sustainment programs result in several thousand changes to the transmission system each year. It is critical to worker safety that these changes be reflected on the operating diagrams correctly and in a timely fashion.

4.5 Summary of Expenditures

During 2008 and 2009, there was a major capital investments in the NMS Upgrade. This investment was required for end of life replacement of both hardware and software, and to ensure regulatory compliance with North American Electric Reliability Corporation's (NERC) standards.

The 2010 bridge year is notably higher than historic years due to increased costs to support the larger NMS infrastructure, SCADA Hub sites, increased NERC Cyber monitoring requirements and the Green Energy Transmission system impacts.

The spending requirement for test year 2011 is $24.8 million which is a 9.7% increase in spending from bridge year 2010. The spending requirement for 2012 is $25.9 million which is an increase of 4.4% over the 2011 spending. The increase in spending over the bridge year is attributable to increased operations tools support costs for the NOMS system upgrade and additional operating tools required to manage the Transmission system impacts of the *Green Energy and Green Economy Act, 2009*.

The risks of not proceeding with these levels of work would result in the failure of the Operating Centre to function as required including:

- Failure to maintain software licenses and vendor maintenance contracts and appropriate support staff would result in prolonged unavailability of critical facilities (ie. NOMS & NMS) required to support the operation of the transmission system.
- Failure to adequately support the Field Switching program would have a severe negative financial impact due to long delays in performing planned work.
- Failure to perform load transfer studies would result in diminished system reliability, increased negative impact on customers and would adversely affect worker safety.
- Failure to maintain the accuracy of operating diagrams in a timely fashion would seriously affect worker safety, e.g., potential for incorrect switching, re-energizing a system element while others are working on the equipment.

5.0 ENVIRONMENT, HEALTH AND SAFETY

This program supports environment, health and safety programs that are required to meet legal obligations and ensure a level of due diligence commensurate with the size and scale of Hydro One Transmission. In addition, the program funds activities to assist in meeting the Corporation's Environmental and Safety performance targets as described in Exhibit A, Tab 4, Schedule 1.

Activities funded by this program include:

- Occupational and non-occupational injury/illness support which includes medical assessments of workplace injuries and the Care Management Program which provides targeted assistance and medical/supervisory support mechanisms for employees who have experienced long-term absences from work;
- Hazardous Materials Management which identifies hazardous materials and establishes a protocol for on-going management of these materials in the workplace per the Occupational Health and Safety Act and the Workplace Hazardous Material Information System;
- School presentations, media campaigns and educational material to inform and educate members of the public about the hazards of Hydro One's assets;
- Proactive forums to assist the health and safety of employees by raising awareness and providing education about health, wellness and lifestyle issues; and
- A Learning Management System which is the development and administration of all training events in an integrated system.

The bridge year increases over historical spending is related to expansion of current initiatives and the corporate wide program Journey to Zero and ISO 14001/OHSAS 188001 Registration that are targeted to help achieve the Hydro One strategic objective of an injury-free workplace. Also included are trades and technical training programs. Training requirements are increasing due to the influx of new staff required to complete the planned work program and replace those who will retire in future years.

The expenditure requirement for this program is $3.5 million in test years 2011 and $4.0 million in 2012. The 54% increase for Environment, Health and Safety of 2012 from the bridge year, is due to the continued enhanced initiatives to help Hydro One build and improve on the existing safety culture and maintain high standards for public safety, as well as the increased workloads due to the influx of new staff.

Reductions in this program would present significant risks of noncompliance with safety regulations, especially considering that Hydro One Transmission is undertaking increased work programs with a greater number of new staff that need support and direction. As well, safety performance would suffer and there would be increased risk to safety with reduced safety awareness programs.

6.0 CONTRACTS AND CUSTOMER BUSINESS RELATIONS

Improving the level of service that the Company provides to customers is a key objective of Hydro One. While it is the role of each employee to ensure they work towards improving customer satisfaction, Customer Business Relations focuses its efforts on managing the relationship with the Large Customer segment. This includes Hydro One Transmission-connected industrial customers, LDC's and transmission-connected generators.

The transmission industrial and LDC long term satisfaction target of 90% was met in 2008 and 2009 with scores of 91% and 90% respectively. The transmission generators score also improved from 83% in 2007 to 85% in 2008 but dropped to 80% in 2009.

The objective of Customer Business Relations is to maintain satisfaction levels and improve in areas where necessary, while working within regulatory boundaries to ensure compliance. The core work programs include contract management, program implementation, customer communications, operational and business support and customer connection project coordination. Planned long term initiatives involve improved customer communications through enhanced Web self service, skills training and a new Customer Relationship Management system to increase customer knowledge and improve commitment tracking and reporting

6.1 Contracts and Customer Business Relations Activities

Contracts and Customer Business Relations activities include:

- Coordinating new and modified connection requests.
- Managing transmission connection agreements.
- Managing the Wholesale Meter Exit program and the Transitional Meter Service Provider (MSP) fee program.
- Implementing and administering a new tracking process for customer contracts.
- Enhancing customer account management and commitment tracking systems to improve customer service and sharing of customer information within Hydro One.
- Meeting with each customer annually to identify any issues and follow up on satisfactions surveys.
- Managing Hydro One's large customer web services, including annual enhancements to improve customer experience with web access
- Continuing to manage customer programs and communications.

Bridge year spending has increased relative to historical as a result of added work load associated with new generation customers and added customer interface required to manage the larger work programs, as well as new hires required for succession planning.

The spending requirement for this program for test year 2011 is $5.3 million which is a 2% increase in spending from bridge year 2010. The spending requirement for 2012 is $5.5 million which is an increase of 4% over the 2011 spending, largely due to cost escalation.

The improvement in customer satisfaction over the past five years and continued performance above 90% for large customers has shown that satisfied customers are less work. The risks of not proceeding with this work would result in lower customer satisfaction and a subsequent increase in work load, as well as reduced efficiencies in meeting customer needs in terms of longer term planning to coordinate customer and Hydro One Transmission's work.

SUMMARY OF SHARED SERVICES – OM&A

Hydro One Shared Services are comprised of Common Corporate Functions and Services ("CCFS"), Asset Management Services, Information Technology ("IT"), Cornerstone, Cost of Sales to external parties and Other OM&A. Other OM&A includes the capitalized overhead credit, the environmental provision credit, indirect depreciation and other costs.

CCFS includes Corporate Management, Finance, Human Resources, Corporate Communications and Services, Legal, Regulatory Affairs, Corporate Security, Internal Audit, and Real Estate. Common Asset Management services include Strategy and Business Development, System Investment, Work Program Optimization, Business Integration, Asset Management Processes and Policies and Business Transformation. IT and Cornerstone activities include providing and managing computer systems (for example, hardware and software) and IT infrastructure.

Hydro One utilizes a centralized shared services model to deliver its common services. The common services are delivered to the Transmission and Distribution businesses within Hydro One Networks Inc., and to the legal entities Hydro One Inc., Hydro One Telecom Inc., Hydro One Networks Brampton Inc., and Hydro One Remote Communities Inc. The centralized shared services model has allowed Hydro One Inc. to efficiently deliver key common services across the whole company in a cost-effective manner.

Many organizations have adopted a shared service model as an effective method of delivering common services to multiple subsidiaries and/or multiple business units. Hydro One adopted this model when it was established in 1999. The additional cost to establish the common functions in each of its subsidiaries would be cost prohibitive. In addition, the shared service model allows for the delivery of specialty services (i.e. Tax, IT systems and processes) without the need for having multiple experts in many areas.

This shared services model is a recognized business concept which has many benefits including:

- Minimization of the work force through commonly available specialist expertise and resources;
- Ensuring consistent policy and governance framework processes;
- Rationalizing and providing consistent levels of service across the organizations (for example, consolidation of office space, centralization of human resources, pay and financial services, infrastructure support);
- Using common technology systems and platforms and providing better access to information (for example, implementation of common financial and work material management systems);
- Synergies from economies of scale (for example, accounts payable processing, common procurement process and management of supplier relationships); and
- Increased flexibility to pursue outsourcing of services where appropriate.

Shared services cost levels are fully reviewed as part of the annual business planning process (see Exhibit A, Tab 12, Schedule 1).

Table 1 summarizes the Transmission portion of the Shared Services and Other OM&A Costs over the Historic, Bridge and Test years.

Table 1
Allocated Transmission Shared Services and Other OM&A Costs ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Common Corporate Functions and Services	64.1	64.5	71.8	81.3	79.7	86.6
Asset Management	25.9	31.8	40.0	33.0	35.5	36.0
Information Technology	46.2	50.7	56.2	68.1	67.5	68.5
Cornerstone	2.7	1.5	4.0	(9.4)	(12.5)	(21.4)
Cost of Sales	14.5	20.5	13.5	15.8	14.9	8.5
Other OM&A	(72.5)	(109.6)	(114.7)	(130.3)	(138.3)	(131.8)
Total	**80.9**	**59.4**	**70.8**	**58.6**	**46.9**	**46.4**

For the 2007-2012 period, Hydro One has applied a cost allocation methodology developed by Black and Veatch Corporation (B&V) which utilizes a breakdown of activities and drivers. In 2009, the Company commissioned B&V to update the methodology to allocate common costs among the business entities using the common services (as discussed in Exhibit C1, Tab 5, Schedule 1). The approach utilizes a further breakdown of activities and drivers and is used in this application.

The following Table 2 provides an overview of the various shared services cost categories for 2011 and 2012 showing the total costs as well as the allocated Transmission costs.

Table 2
Shared Services and Other OM&A Costs ($ Millions)

Function / Service	2011 Total	2012 Total	2011 Tx Allocation	2012 Tx Allocation
Common Corporate Functions and Services	154.9	162.2	79.7	86.6
Asset Management	74.9	75.8	35.5	36.0
Information Technology	148.1	150.5	67.5	68.5
Cornerstone	(17.9)	(29.1)	(12.5)	(21.4)
Cost of Sales	24.7	13.8	14.9	8.5
Other Shared Services	(253.4)	(242.1)	(138.3)	(131.8)
Total	**131.3**	**131.2**	**46.9**	**46.4**

The change in 2011 as compared to 2009 is primarily related to:

- Higher CCFS costs due mainly to higher Real Estate costs for additional work space as a result of the growth in the Company's work program; increased Human Resource support as a result of the larger work program and succession planning; increased costs related to long term relationship building and negotiations with First Nations and Métis groups (see Section 1.4 of Exhibit C1, Tab 2, Schedule 7) and higher General Counsel & Secretariat costs related to the records management project and increased workload due to the GEA. These increases are partially offset by decreased Finance costs as the IFRS project nears completion.
- While overall Asset Management costs increased due to growth in the Distribution and Transmission SD&O work programs (see Exhibit C1, Tab 2, Schedule 8 for details), Transmission OM&A costs decreased over this period due a shift in the allocation of these costs;
- Higher IT costs due to increased sustainment work effort for the completed Cornerstone Phase 1 and Phase 2 projects (see Exhibit C1, Tab 2, Schedule 9 for details);

- Lower Cornerstone costs due to a reduction in overall development costs, compounded by greater savings as process improvements from Cornerstone are leveraged in the business.
- Increased Cost of Sales as a result of activities related to revenue metering projects per the IESO requirements, and traditional work performed for OPGI;
- Lower Other Shared Services resulting from the growth in the capital work, thus generating higher overhead credits.

In the exhibits following, information is provided on the following areas:

- Common Corporate Functions and Services;
- Asset Management Services;
- Information Technology;
- Cornerstone;
- Cost of Sales;
- Other OM&A.

SHARED SERVICES - COMMON CORPORATE FUNCTIONS AND SERVICES & OTHER OM&A

The Corporation has identified certain functions that provide common services to all business units. It was determined that these functions could be shared effectively by all business units, avoiding costly and unnecessary duplication. These costs are referred to as Common Corporate Functions and Services ("CCFS"). Included in this exhibit is a discussion of CCFS costs and activities as well as Other OM&A which is comprised of credits associated with Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs.

1.0 COMMON CORPORATE FUNCTIONS AND SERVICES

Table 1 presents, for comparison purposes, the total Common Corporate Functions and Services ("CCFS") costs over the Historic, Bridge and Test years as well as the 2011 and 2012 Transmission allocation amounts.

Table 1
Total 2007 - 2012 CCF&S Costs and 2011/2012
Allocation to Transmission ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Corporate Management	5.6	6.0	6.0	5.3	5.2	5.2	2.6	2.7
Finance	22.4	27.7	30.7	30.1	29.1	28.8	14.5	14.4
Human Resources	12.2	13.6	15.6	17.6	18.6	19.3	9.6	10.0
Corporate Communications	7.0	8.3	10.1	11.7	12.4	16.6	6.0	10.3
General Counsel and Secretariat	7.9	6.4	6.6	8.1	9.2	8.6	4.8	4.5
Regulatory Affairs	21.3	19.3	19.5	20.2	20.7	22.6	11.3	13.2
Corporate Security	1.7	2.1	2.1	2.7	2.8	2.9	1.3	1.3
Internal Audit	2.6	2.5	2.7	2.9	3.0	3.1	1.9	1.9
Real Estate & Facilities	37.5	41.9	50.6	58.6	54.0	55.0	27.6	28.3
Total CCF&S Costs	**118.1**	**127.7**	**143.8**	**157.2**	**155.0**	**162.1**	**79.7**	**86.6**

Total CCFS costs increased by $11.3 million from 2009 to 2011 primarily due to the following factors; higher Real Estate costs for additional work space as a result of the growth in the company's work program; increased Human Resource support as a result of the larger work program and succession planning; increased costs related to long term relationship building and negotiations with First Nations and Métis groups (see Section 1.4) and higher General Counsel & Secretariat costs related to the records management project and increased workload due to the GEGEA. These increases are partially offset by decreased Finance costs as the IFRS project nears completion and lower Corporate Management costs.

From 2011 to 2012, total CCFS costs increase by $7.0 million primarily due to new cost recovery charges from the National Energy Board, increased OEB fees and higher Corporate Communications costs for co-ordination of the development and partnership activities of each of Hydro One's major GEA projects. These increases are partially offset by decreased General Counsel costs due to the completion of the Records Management project.

Details on costs and work in each CCFS function are provided in the following sections.

1.1 Corporate Management

The following Table 2 provides a summary of Corporate Management costs:

Table 2
Corporate Management Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Cost	**5.6**	**6.0**	**6.0**	**5.3**	**5.2**	**5.2**	**2.6**	**2.7**

Corporate Management represents those functions responsible for providing overall strategic direction to the corporation, including the Board of Directors, Treasurer's Office, the Chief Executive Officer ("CEO"), Chief Financial Officer ("CFO"), the General Counsel and Secretary as well as the costs of certain supporting functions, such as Executive Office support.

The President, CFO and General Counsel & Secretary are considered to be part of Hydro One Inc. and provide services to Hydro One Networks Inc.

The General Counsel and Secretary function provides advice and support to the Board of Directors and Corporate Officers. It provides advice and training, reports on Code of Conduct, reports on activities related to the Freedom of Information and Privacy Act as well as the Federal Personal Information Protection & Electronic Documents Acts ("PIPEDA").

The CFO is responsible for the oversight of the Finance function and the reporting of information to Hydro One subsidiaries, regulators, investors and the shareholder. This includes the review and approval of financial and investment decisions, business and strategic plans and ensuring integrity of, and compliance with, internal controls over regulatory, financial and accounting activities.

The allocation of the costs associated with the activities of Corporate Management are governed by a Service Level Agreement between Hydro One Inc. (HOI), Hydro One Networks Inc. (HONI) and the legal subsidiaries as outlined in Exhibit A, Tab 7, Schedule 3. This exhibit also describes the activities performed by HOI, HONI and the amounts allocated to the various subsidiaries.

2008 to 2012 includes a lower level of executive compensation, consistent with the Agency Review Panel (the "Arnett Panel") report.

1.2 Finance

The following Table 3 provides a summary of Finance costs:

Table 3
Finance Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Cost	**22.4**	**27.7**	**30.7**	**30.1**	**29.1**	**28.8**	**14.5**	**14.4**

1.2.1. Overview

Finance provides strategic advice and services related to the planning, processing, recording, reporting and monitoring of all financial transactions taking place within the organization. Clients include parties both internal and external to the organization, depending on the service provided. Services are provided through the following specialist functions:

- Corporate Controllers;
- Corporate Tax;
- Treasury.

Finance costs have decreased from 2009 to 2011 primarily due to lower IFRS implementation costs and the completion of Cornerstone Phase 2, resulting in decreased Inergi project support. These increases are partially offset by higher insurance costs due to increased insurance premiums and self-insurance costs.

1.2.2. Corporate Controllers

Corporate Controllers provides leadership and direction regarding all business planning, financial reporting, accounting and internal control policies and procedures to ensure statutory and regulatory compliance and consistency with generally accepted accounting principles. This includes leading the IFRS conversion project.

The function oversees the development of actual and forecast financial information and manages reporting processes to appropriate audiences or stakeholders. Corporate Controllers are responsible for establishing and leading the annual business planning and budgeting processes and presentation of the plan to the Board of Directors and the Provincial Government. This function is also responsible for managing and providing direction to the company with respect to matters of internal control, including Organization Authority Registers, financial policies and procedures and providing leadership regarding compliance with Bill 198 and associated Ontario Securities Commission ("OSC") related rules.

Routine financial services, such as Accounts Payable, Accounts Receivable, Fixed Asset Accounting, General Accounting, Planning Budgeting and Reporting support, Pension support and a number of administrative procedures are outsourced to Inergi. These services are a major portion of the Corporate Controllers costs.

The total cost of Corporate Controllers activities in 2011 and 2012 are $22.7 million and $22.5 million respectively, of which $11.0 million and $10.9 million are allocated to Transmission. From 2009 to 2011, Corporate Controllers costs decline by $3.6 million due to lower IFRS implementation costs as well as lower Inergi project support due to the completion of phase 2 of Cornerstone.

1.2.3 Corporate Tax

Corporate Tax manages the tax affairs, (compliance, audits and planning), for each corporation within the Hydro One group including corporate income and capital taxes, the federal goods and services tax, the provincial retail sales tax, debt retirement charge, payroll and non-resident withholding tax and the employer health tax. Corporate Tax ensures that internal and external tax compliance requirements are met.

The costs associated with Corporate Tax activities are $1.8 million in 2011 and 2012 with approximately $0.9 million charged to Transmission in both years.

1.2.4 Treasury

Treasury total costs are $7.4 million in 2011 and $7.3 million in 2012. Of these amounts, $2.7 million for 2011 and $2.8 million for 2012 represent costs incurred to:

- execute borrowing plans and issue commercial paper and long-term debt;
- ensure compliance with securities regulations, bank and debt covenants;
- manage the company's daily liquidity position, control cash and manage the company's bank accounts;
- settle all transactions and manage the relationship with creditors; and
- communicate with debt investors, banks and credit rating agencies.

The remaining $4.7 million for 2011 and $4.5 million for 2012 include:

- costs of $4.0 million for 2011 and $3.8 million for 2012 representing costs incurred in relation to assessment of risk, negotiation and purchase of insurance policies, claims management and settlement. These costs represent the premiums paid for third party liability, fiduciary liability, directors and officers insurance, and also the cost of self-insurance for liability exposures that are either not covered by insurance policies or fall below the specified deductibles.

- costs of $0.7 million for 2011 and 2012 representing Decision Support costs for services such as business case review, business valuation, transaction support, and other services as required. The function develops and maintains financial models and provides analytical support for a variety of financial planning and reporting processes;

Hydro One Transmission Business is allocated $2.7 million of the $4.7 million Treasury budget for 2011 and $2.6 million of the $4.5 million budget for 2012.

The cost for other insurance premiums are charged to work programs or are included as an Asset Management cost.

Table 4 shows the premium for all of Hydro One Inc.'s insurance policies and the cost of self insurance for the 2007 to 2012 period. Self insurance costs for the 2011 to 2012 period take into consideration the company's risks exposures, the long-term historical claims experience, the deductible on the liability policies and the costs of insuring the self insured exposures. The increase in 2011 and 2012 self-insurance cost is mainly related to deteriorated loss experience compared to 2009.

Table 4
Hydro One Inc. Insurance Program ($ Millions)

	2007	2008	2009	2010	2011	2012
Hydro One Inc. Insurance Premiums	5.1	4.9	6.2	6.5	6.9	7.1
Self Insurance Cost	1.0	1.6	1.2	2.3	2.3	2.2
Total	**6.1**	**6.5**	**7.4**	**8.8**	**9.2**	**9.3**

1.3 Human Resources

The following Table 5 provides a summary of Human Resources costs:

Table 5
Human Resources Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Cost	**12.2**	**13.6**	**15.6**	**17.6**	**18.6**	**19.3**	**9.6**	**10.0**

The Human Resources ("HR") function exists to enable the success of Hydro One. As a staff function, HR adds value by providing advice, guidance and services to managers (and on their behalf, to employees) which support and optimize the acquisition and management of the workforce, and the treatment of pensioners. HR provides consulting, leadership development and recruiting, diversity and resourcing programs, compensation and benefits and labour relations services.

One of the greatest challenges facing Hydro One is in an area where HR will be expected to play a significant role – the dramatic demographic transition that will be occurring in the Hydro One workforce over the next few years. By December 31, 2011, approximately 1,400 Networks staff (transmission and distribution) will be eligible for undiscounted retirement. By December 31, 2012, approximately 1,600 Networks staff will be eligible for undiscounted retirement. HR is also involved in promoting the development of the skill base and expertise required by Hydro One from graduates of high schools, trades schools, colleges and universities. New staff means extra training which will be provided by HR staff dedicated to this function. Hydro One is currently looking at ways by which to mitigate some of the impact of this "wave" of staffing work; by outsourcing or further automating (IT) some of the more labour intensive components of the hiring processes

The total costs for 2011 and 2012 are $18.6 million and $19.3 million respectively with $9.6 million and $10.0 million allocated to Transmission. The cost increases in from 2009 to 2011 and 2012 are due to the expansion of the HR work program to support increased hiring/staffing levels, not only due to the demographics issue but also due to expanding core SDO work programs; enhanced graduate training and coaching programs; employee engagement survey and advertising.

1.3.1 HR Consulting

Hydro One's HR Consultants provide advice and guidance to managers, supervisors, and employees on a myriad of issues related to HR policies and procedures, collective agreement administration, staffing and other large initiatives that impact staff. Alongside the Generalist consulting group, Hydro One HR contains a number of smaller 'specialist' support/service activities. The Pension and Benefits Section administers the Hydro One Pension Plan for approximately 7,100 pensioners. In addition, this section also administers the benefits programs for all employee groups.

1.3.2 Leadership Development and Recruiting

This function recommends and administers policy in areas related to external hiring and development; in addition it manages all of Hydro One's management/leadership development activities, plus miscellaneous specialized one-off hiring initiatives, as required.

1.3.3 Diversity & Resourcing Programs

This function manages Hydro One's principal[1] cyclical hiring processes - the New Graduate, the Fellowship program, the Co-Op Student/Internship/Developmental, program and the Summer Student Hiring program. Additionally, the unit is responsible for the Hydro One Diversity Program including Women in Leadership and Mentoring.

1.3. 4 Compensation & Benefits

Payroll operations for a Company the size and complexity of Hydro One are both critical and extensive. The labour intensive transactional elements of payroll administration were largely outsourced to Inergi with contract administration within Hydro One to ensure compliance and cost containment. This same group also manages the Short Term Incentive Plan for Management Compensation Plan staff.

Compensation & Benefits also provides regular strategic reporting of HR and Pay data for Senior Management in such areas as retirement demographics, headcount, overtime reports, data for OEB submissions, etc., as well as participating in industry wide compensation, benefit and pension surveys.

[1] Trades staff are hired through the Power Workers' Union Hiring Hall processes.

1.3.5 Labour Relations

Labour Relations exists to provide advice, guidance and training to managers regarding collective agreements and labour legislation and manages the grievance and arbitration process. There are 24 collective agreements plus midterm agreements and letters of understanding that bind the company. In addition, the company must comply with legislation such as the Ontario Labour Relations Act, the Employment Standards Act, the Human Rights Code, etc, all of which require interpretation and advice to Managers.

1.4 Corporate Communications & Services

The following Table 6 provides a summary of Corporate Communications costs:

Table 6
Corporate Communications Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Cost	**7.0**	**8.3**	**10.1**	**11.7**	**12.4**	**16.6**	**6.0**	**10.3**

This function comprises Corporate Communications, First Nations and Métis Relations and Outsourcing Services. The increase in costs from in 2009 to 2011 is primarily as a result of the expansion of First Nations and Métis Relations programs to sustain long-term relationship building and negotiations with First Nations and Métis communities as a result of the growth of Hydro One core SDO work programs including GEA projects. In 2012, costs will increase as a result of additional work requirements to support the GEGEA projects requested by our Shareholder, partially offset by decreased Outsourcing Services costs as a result of the completion of design and development activities associated with the new outsourcing service agreement.

1.4.1 Corporate Communications

Corporate Communications is responsible for managing all communications initiatives for the corporation. Services are provided in respect of communications strategy; media and public relations; issue management; public affairs, community and government relations; corporate reputation; customer communications; advertising, graphic design; writing; employee communications; stakeholdering; and internet/intranet communications. Corporate Communication costs decrease by $0.8 million from 2009 to 2011 due to higher than planned spending on media, research and sponsorships in 2009. From 2011 to 2012 costs increase by $5.0 million as a result of additional work requirements to support the GEGEA projects. The additional work requirements include: coordination of development and partnership activities; coordination with external energy agencies (e.g. - OPA, IESO), Ministries in the Ontario Public Service and internal Hydro One resources regarding major grid projects and initiatives; preparation of risk assessments related to project development phases of Green Energy projects; provision of strategic direction regarding the scope and timing of project development work; participation in pre-public consultations with municipalities and First Nations; representation of Hydro One on external working groups; and development and negotiation of partnership arrangements for major GEGEA investments to support corporate strategy and government objectives.

1.4.2 First Nations and Métis Relations

Another important role that falls within the Corporate Relations function is First Nations and Métis Relations. Hydro One owns assets on reserve lands and within the traditional territories of First Nations & Métis Peoples. Hydro One recognizes that First Nation’s peoples and their lands are unique in Canada, with distinct legal, historical and cultural significance. Forging relationships with First Nation communities based upon trust, confidence, and accountability is vital to achieving our corporate objectives. The First Nations and Métis Relations group encompasses the following functions:

- Sustains long-term capability in the areas of relationship building, negotiations and the successful implementation of on-going programs to achieve Hydro One's goals in the area of partnerships with the First Nations & Metis peoples;
- Develops and maintains key relationships with senior government officials, both federal and provincial, as well as representatives of key businesses including but not limited to other energy companies;
- Monitors jurisprudence which may impact on relationships and negotiations with First Nations & Metis communities;
- Manages First Nations & Métis capacity building to ensure adequate financial and human resources are available to the First Nations & Métis peoples to provide value added input to projects and/or initiatives taken on by Hydro One;
- Coordinates opportunities to educate and share information amongst attendees regarding current jurisprudence and best practices in First Nations & Métis relations;
- Supports procurement opportunities for qualified First Nations & Métis businesses;
- Provides consultation services on projects and/or initiatives that may potentially affect the First Nations & Métis peoples and communities;
- Provides leadership and advice in the building of knowledge and awareness of First Nations issues within the company and with the shareholder; and,
- Develops, in conjunction with the Human Resources and Labour Relations departments, a strategy and implementation plan to enhance the level of First Nations & Metis employment at Hydro One.

First Nations and Métis Relations costs are $3.5 million in 2011 and $3.6 million in 2012 of which $2.1 million is allocated to Transmission in both years. The increase in costs in 2011 and 2012 is required to sustain long-term relationship building, consultation processes and negotiations with First Nations and Métis as a result of the growth of the Hydro One core SDO work programs, including major GEGEA projects.

1.4.3 Outsourcing Services

Outsourcing Services manages the overall business relationship between Hydro One and Inergi LP. Outsourcing Services develops and implements best practice governance processes in order to maximize the value of the existing relationship with Service Provider(s) to the benefit of Hydro One. Outsourcing Services is responsible for the design and development of a new service delivery agreement with Hydro One's existing supplier or other suppliers. Department costs are $3.2 million in 2011 and $2.3 million in 2012 of which $1.7 million and $1.3 million respectively are allocated to Transmission. In 2012, Outsourcing Services costs decrease by $0.9 million because the work associated with the design and development of the new service delivery contract will be completed.

1.5 General Counsel and Secretariat

The following Table 7 provides a summary of the costs of the General Counsel and Secretary function:

Table 7
General Counsel and Secretary Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Cost	**7.9**	**6.4**	**6.6**	**8.1**	**9.2**	**8.6**	**4.8**	**4.5**

1.5.1 Overview

The offices of the General Counsel and Secretary ("GC&S") provide legal advice and direction to Hydro One and its operating subsidiaries, as well as overall guidance in the areas of corporate structure, governance, business ethics and the business code of conduct. The GC&S function consists of two main functions: Law and the Corporate Secretariat. The Corporate Secretariat reports to the General Counsel.

The GC&S functions in Hydro One Networks Inc. consist of:

- Provision of legal services to all business units including the Company's major borrowing and financing initiatives, regulatory activities, transmission and distribution businesses (contracts, other commercial matters), employment, including pension and benefits, health, safety and environment, litigation, all Board of Directors related activities, and arranging for the provision of legal services to the Corporation. The volume of these services is driven by capital and OM&A activities, as well as increasing regulatory and legislative oversight functions.
- Overseeing the Law and Corporate Secretariat functions.
- Ensuring compliance with legal and regulatory requirements.

Hydro One does most of its legal work in-house, except when the in-house expertise is not available (for example, tax, labour) or when the workload exceeds the capacity of the internal legal group.

The increase in costs for General Counsel and Corporate Secretariat in 2011 compared to 2009 is driven mainly by increased work requirements related to the GEA and the Records Management project. Examples of the additional workload include, more procurement related work due to the larger work program, review of legal agreements associated with distributed generation and real estate related legal work to obtain land and land rights for new development projects. Costs decrease from 2011 to 2012, as a result of the completion of the Records Management project.

1.5.2 Law

Law provides legal advice to all business units of the Corporation, acting as an internal "law firm" for the corporation. It advises on most aspects of law affecting the corporation, and relies on its experience and knowledge of the Company's business in providing economic and timely advice. The Law function maintains core knowledge of the law and the Company's business.

1.5.3 Corporate Secretariat

The Corporate Secretariat provides support to the Office of the Chair, the Board of Directors and its Committees, including the administrative aspects of the Board and its meetings. It provides advice and analysis with regard to a variety of board-related matters, including corporate governance best practices and emerging trends and issues. It provides advice and direction with regard to the business Code of Conduct, ensuring appropriate actions to resolve known or suspected violations. This group also has responsibility for Community Citizenship initiatives advising the Corporation on compliance with privacy legislation, and administering requests for information under the Freedom of Information and Protection of Privacy Act.

1.6 Regulatory Affairs

Table 8 provides a summary of Regulatory Affairs costs:

Table 8
Regulatory Affairs Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Regulatory Affairs	11.2	10.3	9.3	10.0	10.3	12.1	5.6	7.0
OEB/NEB Costs	10.1	9.0	10.2	10.2	10.4	10.5	5.7	6.2
Total Cost	**21.3**	**19.3**	**19.5**	**20.2**	**20.7**	**22.6**	**11.3**	**13.2**

1.6.1 Overview

Regulatory Affairs consists of Regulatory Affairs and the Pricing and Load Forecast Management functions. The costs of this function include Hydro One's share of the Ontario Energy Board ("OEB") costs, including the OEB quarterly assessment costs, OEB proceeding-specific costs and OEB-ordered intervener cost awards. OEB assessed costs are approximately $10.4 million of total 2011 costs and $10.5 million of total 2012 costs. The increase in Regulatory Affairs costs from 2009 to 2011 is primarily due to lower than planned labour costs in 2009 due to vacancies. From 2011 to 2012 costs increase by $1.9 million as a result of new National Energy Board cost recovery fees charged to Hydro One as well as higher incremental rate hearing costs.

1.6.2 Regulatory Affairs Activities

Regulatory Affairs is responsible for managing the Company's relationships with the regulatory bodies with which it interacts, including the Ontario Energy Board, the IESO, the OPA, and the National Energy Board. Through this function, it is responsible for developing strategy and coordinating the Company's submissions to these bodies and participation in regulatory initiatives such as the development of the Transmission System Code ("TSC").

Regulatory Affairs is involved in the coordination, preparation and processing of applications, as well as providing support to witnesses and business support staff. Such proceeding-specific services are provided for a wide range of applications, including distribution and transmission rates, transmission leaves–to-construct, merger/ acquisition/ amalgamation/ divestiture applications and area and system supply planning. In addition to proceeding-specific work, Regulatory Affairs is responsible for a variety of ongoing reporting and other activities. The function prepares quarterly and annual reports required under OEB Reporting and Record-keeping Requirements. Work includes meeting, reporting on, and responding to Regulatory Compliance Issues. Pricing and cost allocation analysis and support are also provided within Regulatory Affairs for rate applications. This includes development of rate structures and rates for the regulated transmission and distribution tariffs applicable to the company and provides support in submitting and defending rate proposals. The function also assists with the implementation of approved transmission and distribution rates.

Load Forecasting and Load Data Management units are included within the Regulatory Affairs group. Load Forecasts are developed to enable system planning and financial planning which underlie the company's financial forecasts. The Load Forecast function provides load forecast data including the capture of CDM impacts. Load Forecast staff support Hydro One Networks business units and the OPA with forecasting analysis and evaluation covering time of use, bypass and embedded generation. Load Data Management provides analytical support for conservation and demand management projects and provides load research analysis.

Regulatory costs in 2010 through 2012 are being driven by an extremely aggressive regulatory program including a major Transmission Cost of Service Application for 2011 – 2012 Revenue requirement, several leave to construct applications, asset sales and service territory transfers to remove long term load transfers.

The OEB is continuing a busy and challenging program of reviews and initiatives, most of which involve Hydro One. In 2010 the Board is conducting several generic proceedings on issues such as:

1. Facilitating the participation of First Nation and Métis in Board processes;
2. Developing system reliability standards for distributors; and,
3. Issuing a Transmission Planning Guideline relating to the development work on connecting renewable generation.

1.6.3 Ontario Energy Board Costs

Under the *Ontario Energy Board Act, 1988,* the Ontario Energy Board is required to recover all of its annual operating costs. Almost all of its costs are recovered from gas and electricity distributors and electricity transmitters. A small fraction of OEB costs are recovered from the IESO, the OPA, OPG and from licensing fees and penalties. OEB costs that are subject to recovery include its staff costs, office space costs, administration costs and overheads. These costs are allocated to one of six categories – electricity distribution, electricity transmission, gas distribution, IESO, OPA and OPG. Hydro One Networks' allocation arises from OEB costs related to electricity distribution and transmission.

1.7 Corporate Security

The following Table 9 provides a summary of Corporate Security costs:

Table 9
Corporate Security Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Cost	**1.7**	**2.1**	**2.1**	**2.7**	**2.8**	**2.9**	**1.3**	**1.3**

The Corporate Security Services (CSS) function exists to enable the success of Hydro One primarily in the protection of assets (assets include people, property and information) and assisting in the reliable delivery of electricity. CSS adds value by providing advice, guidance, investigative and intelligence gathering expertise and services to managers (and on their behalf, to employees) which support and optimize the reliable delivery of electricity and the protection of Hydro One assets. Effective asset protection and recovery can be the primary differentiating factor between success and failure for critical infrastructure organizations such as Hydro One. This is achieved by effective corporate security policies, directives, guidelines and services, which can significantly enhance employee and business productivity.

The total costs in 2011 and 2012 are $2.8 million and $2.9 million respectively of which $1.3 million was allocated to Transmission in both 2011 and 2012. In the last decade there has been a dramatic increase in the focus on the protection of critical infrastructure and the industries that comprise these key social, safety and security functions due to the recognition of the criticality for electricity delivery assets, increased thefts of copper and global and domestic terrorist activities. Corporate Security costs increase by $0.7 million from 2009 to 2011 due to lower than planned labour costs in 2009 and normal salary escalation.

1.8 Internal Audit and Risk Management

The following Table 10 provides a summary of Internal Audit and Risk Management costs:

Table 10

Internal Audit and Risk Management Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Cost	**2.6**	**2.5**	**2.7**	**2.9**	**3.0**	**3.1**	**1.9**	**1.9**

Internal Audit reports to the CEO and the Audit and Finance Committee of the Board of Directors. It is an independent, objective, assurance and consulting activity designed to add value to and improve Hydro One's operations. The mandate for Internal Audit is to provide independent assurance to the CEO and Board that internal controls are adequate in areas of high-risk and to follow-up and report on management actions to address findings from past audits. The Corporate Business Risk Management function supports the CEO by:

- developing business risk management policies, frameworks and processes;
- introducing and promoting new techniques for assisting management to identify and evaluate risks within their operations;
- preparing corporate risk assessments; and,
- maintaining a framework of key business risks.

The department helps the Company accomplish its objectives by bringing a systematic and disciplined approach to evaluating and improving the effectiveness of risk management, internal control and governance processes. The total costs for this function in 2011 and 2012 are $3.0 million and $3.1 million, respectively, of which $1.9 million is allocated to Transmission in both 2011 and 2012.

1.9 Real Estate and Facilities

Table 11 provides a summary of Real Estate & Facilities costs:

Table 11
Real Estate & Facilities Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Costs	37.5	41.9	50.6	58.6	54.0	55.0	27.6	28.3

1.9.1 Overview

The total cost for the Facilities and Real Estate function in 2011 is $54.0 million, with $27.6 million allocated to Transmission. The 2012 cost is $55.0 million, with $28.3 million of that allocated to Transmission. The 2011 and 2012 funding is required for the expanded facilities work program that responds to current and future anticipated Company work space accommodation needs. The facilities work program accounts for approximately 83% of total funding in test years 2011 & 2012. The Company workload continues to drive the need to provide for additional work space to accommodate additional staff levels in the administrative office space and in the field service centres.

1.9.2 Real Estate Services ("RES")

Real Estate Services manages Hydro One's land rights portfolio across the Province. This involves ensuring that rights across over 200,000 acres of owned corridor, easement and "statutory right" properties are maintained, and that new rights are acquired as necessary to ensure the safe and reliable operation of the transmission system. In addition, Real Estate oversees the management of Hydro One's rights associated with distribution and transmission lands, stations and other property.

Key work activities include:

- managing acquisition of new real estate rights; ((This includes Company transmission development and reinforcement project initiatives across the Province including enabling transmission of renewable power sources)
- managing the Provincial secondary land use program on behalf of the shareholder / Province e.g. leasing transmission corridor lands to external parties;
- managing easement, other rights agreements on public/private sector, railway and other lands;
- managing First Nations settlements and First Nations liaison activities;
- managing about 500,000 unregistered, low-voltage, real estate rights agreements;
- providing specialized real estate service activities including managing property tax payments to municipalities, appealing property tax assessments, and providing employee relocation services.
- Maintenance of Geographic Information System (GIS) – property record database.

More specific support is provided on a selected project basis. This includes provision of land ownership information, damage claim settlement, road access and other rights acquisitions.

Specialized real estate services are provided as necessary. This includes assessment appeals, payment of property taxes on distribution lands/buildings, and employee relocation services as appropriate.

1.9.3 Facilities

Facilities costs are largely driven by company work programs and factors such as corporate staff levels, changing business and operating requirements and fixed cost contractual obligations. Also, the current regulatory environment (including health and safety requirements) ultimately impacts operating costs.

The Facilities work program includes all aspects of company work space requirements which comprise not only company-owned facilities, but management of the portfolio of leased facilities and oversight of the construction of new facilities. The Facilities function manages all of the building and site facilities across the Company. This includes leasing costs and contract management for head office. In addition, it includes costs for administrative facilities, service centres, and other work locations (for example, the London Call Centre The Facilities Organization is responsible to ensure program delivery in terms of service levels, planned capital improvements and providing for Company accommodation needs.

The Facilities Program focuses on providing employee workspace at sites across the province including head office, administrative and service centres, the OGCC, and other work locations (for example, the London Call Centre, and the Ontario Grid Control Centre).

Providing adequate workspace, storage and garage facilities for employees and trades is critical to the effective undertaking of organizational work programs. Equally important is ensuring that new or existing employee workspaces are consistently maintained to a standard that meets current work requirements and complies with all corporate, legislative and other related health, safety and environmental standards.

This Program includes:

- Providing accommodation strategies and acquiring new employee / trades workspace in line with operational requirements.
- Management of 47 contract lease agreements for workspace rented from other parties, including renewals and contractual obligations undertaken regarding payment of rent, operating expenses and taxes
- Coordination of activities related to the ongoing management, operation, maintenance and inspection of 90 Administrative/Service Centres and Ontario Grid Control Centre.
- Provision of support services for Head Office space, such as provision of office supplies and equipment, coordination of office moves, records management and tenant services.

The Facilities work program is extensively driven by fixed-cost contractual obligations which arise primarily through relationships with external landlords. For example, rent, operating and tax costs are specified in formal lease agreements and opportunities to significantly amend these set costs typically do not materialize until the agreement expires. Other fixed costs are represented by negotiated contracts with internal and external service providers for base level facility maintenance (for example, administrative/service centre building maintenance, janitorial and snow removal, minor repairs, building component inspections) and similar activities. These contracts focus on maintaining facilities in a condition that meets current employee work requirements and corporate/legislative requirements.

Fixed facility cost components (for example, utilities, property taxes, operational costs) are expected to continue to rise. The test years indicated funding also takes into consideration changing factors in the operating environment.

2.0 OTHER OM&A

Other OM&A is comprised of Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs as listed in Table 11.

Table 11
Total Transmission Other OM&A ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Capitalized Overhead	(70.4)	(81.0)	(94.7)	(117.8)	(126.3)	(121.1)
Environmental Provision	(5.2)	(3.5)	(2.5)	(5.5)	(7.3)	(7.8)
Indirect Depreciation	(4.1)	(4.1)	(5.2)	(4.6)	(5.1)	(5.0)
Other	7.2	(21.0)	(12.2)	(2.4)	0.4	2.1
Total	(72.5)	(109.6)	(114.6)	(130.3)	(138.3)	(131.8)

2.1 Capitalized Overhead Credit

Table 12
Transmission Corporate Overhead Credit ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Transmission	(70.4)	(81.0)	(94.7)	(117.8)	(126.3)	(121.1)

Capitalized overheads represent that portion of allocated shared corporate and/or business unit functions and services that are deemed through the capital overhead rate to be supportive of Capital projects as opposed to OM&A based projects. These costs are included in shared services and in the lines of businesses. The capital overhead rate determines the costs capitalized. OM&A expense is thus reduced by the capitalized amounts.

The capitalized OM&A costs are distributed to Capital projects based on the allocation methodology derived through the accepted Black & Veatch study (See Exhibit C1, Tab 5, Schedule 1).

2.2 Environmental Provision

Table 13
Transmission Environmental Provision ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Transmission	(5.2)	(3.5)	(2.5)	(5.5)	(7.3)	(7.8)

In 2001, Networks business recognized a liability on its balance sheet for the present value of future estimated environmental expenditures necessary to deal with legacy contaminated lands and the implementation of remedial measures to treat, remove or otherwise manage the contamination. The change in accounting policy from the previous as-incurred basis was adopted to align with the theoretically stronger U.S. generally accepted accounting principle that was expected to be imminent in Canada. Environmental work is initially recognized in the sustaining work program. The amount is then removed from OM&A and the liability / provision is amortized by the amount of the expenditures incurred. The resultant impact on OM&A expense of this environmental work is nil, since the amortization expense is grouped with 'Depreciation and

Amortization' on the operating statement and the balance is transferred from OM&A to Depreciation expense.

The increase in the credit in from 2009 to 2011 results from increased PCB removal program requirements in order to meet the 2008 Federal PCB Regulations.

2.3 Indirect Depreciation

Table 14
Transmission Indirect Depreciation ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Transmission	**(4.1)**	**(4.1)**	**(5.2)**	**(4.6)**	**(5.1)**	**(5.0)**

Transportation and Work Equipment ("TWE") charges in the OM&A work programs include depreciation expense associated with the asset being used. For accounting classification purposes it is necessary to remove this depreciation amount from OM&A and appropriately charge it to Depreciation Expense. The credit increases in the test years due to the expanded use of T&WE in the larger SDO work program.

2.4 Other

Table 15
Transmission Other Costs ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Transmission	**7.2**	**(21.0)**	**(12.2)**	**(2.4)**	**0.4**	**2.1**

These costs represent material unexpected or non-recurring expenses. For example they include items such as insurance rebates, adjustments to provisions, vacation reserves, Gregorian or fiscal adjustments and inventory adjustments.

SHARED SERVICES OM&A- ASSET MANAGEMENT

1.0 OVERVIEW

The Transmission and Distribution businesses are operated using the Asset Management model, which the company adopted in 1998. The model separates the planning, decision-making and approvals associated with customer, system and asset needs from the services functions including engineering, construction, as well as customer and grid operations which carry out these plans. The functions work collaboratively in order to achieve corporate strategic objectives. This separation of functions is a common industry practice in today's utilities and reflects the different skills required for these functions. By applying this model, Hydro One Networks Inc. can make management decisions involving customer and asset requirements on a consistent basis across its entire service territory. The Asset Management model is further discussed in Exhibit A, Tab 4, Schedule 1.

Asset Management remains focused on ensuring, and being able to demonstrate, that the necessary transmission and distribution assets are planned, acquired, constructed, maintained and operated to deliver the required function and level of performance expected by customers in a sustainable manner. The Asset Management function balances the needs of customers, various economic and operational regulatory bodies, the company's assets and systems, the shareholder and the people of Ontario in delivering on the following accountabilities:

- Developing an asset plan for the sustainment, development and operation of the Transmission and Distribution system;
- Optimizing the release, bundling and sequencing of the work to ensure the effective delivery of the programs and projects within the plan;

- Redirecting projects and programs in response to new or unforeseen factors and drivers;
- Monitoring, evaluating and reporting upon progress, accomplishments and cost metrics of the various programs and projects;
- Identifying, assessing and scoping system augmentation, load connections, generation connections, and interconnections with neighbouring systems to address issues related to reliability, customer supply security and changes in the province's generation portfolio;
- Developing, integrating, and implementing asset strategies and investment plans to support corporate objectives, executing OPA programs (such as conservation and demand management, or the Feed-in-Tariff Program), and fulfilling government policies;
- Pursuing business development opportunities, and productivity improvement initiatives; and
- Influencing the business and regulatory environment to ensure customer needs and business objectives (safety, regulatory compliance, environmental performance, etc.) are met in an effective and efficient manner.

Effective delivery of these accountabilities is key to the Company's success in achieving the balance noted above.

The Asset Management function is undertaking initiatives to improve the AM information, reporting, analytics, processes and training that are required to support asset lifecycle planning decisions, business planning processes, rate filings, regulatory compliance and work execution..

The cost profile for Asset Management is presented in Table 1 below.

Table 1
Asset Management Function ($ Millions)

Function/Service	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Strategy & Business Development	5.9	6.3	7.5	11.2	12.5	13.0	3.5	3.7
System Investment	21.7*	24.0	31.5	36.9	38.5	37.9	19.5	18.2
Work Program Optimization	3.8	3.4	3.1	4.5	4.9	5.0	3.9	4.0
Business Integration	9.1	9.4	11.8	10.2	11.9	12.4	6.5	6.8
Business Transformation	3.4	2.6	1.9	2.6	2.4	2.9	1.1	1.6
Real Estate & Facilities	-	-	-	-	-	-	-	-
Contract & Business Relations	-	-	-	-	-	-	-	-
Processes and Policies	1.0	1.3	3.5	4.4	4.6	4.6	1.0	1.9
Total Costs	**44.8**	**47.1**	**59.3**	**69.7**	**74.9**	**75.8**	**35.5**	**36.0**

** System Investment cost was adjusted downward by $1.0 million in 2007, the amount is now shown in Processes and Policies.*

As shown in Table 1, the cost associated with achieving Asset Management work in 2011 is $74.9 million, and $75.8 million in 2012. The portion of the total cost attributable to the Transmission business is $35.5 million in 2011, and $36.0 million in 2012. Refer to Exhibit C1, Tab 5, Schedule 1 for further details on the percentages used to allocate costs into Transmission and Distribution components.

Asset Management is one of several work delivery lines of businesses and its focus is the work initiation stage of the work delivery chain. As such, the rising core sustaining, development, and operations work program volumes have necessitated increased work volumes for the units of business in the work delivery chain, including Asset Management resulting in upward cost pressures.

The primary activity influencing Asset Management costs in 2011 and 2012 is the growth in the overall levels of core capital and OM&A sustainment, and development related work, which is also driven by the initiatives outlined in the Green Energy and Green Economy Plan, found in Exhibit A, Tab 11, Schedule 4.

The overall growth in the work program requires additional system and investment planning, work scoping, controls, monitoring and reporting. Legislative initiatives (for example, new LDC MW targets relating to CDM initiatives, and Smart Meters) and compliance activities (e.g. NERC, NPCC, OSC, Bill 198 and IFRS) have contributed to increased costs. The Cornerstone initiative has required experienced Asset Management staff to ensure business processes are streamlined to improve business efficiency; experienced staff will continue to be required for subsequent phases of Cornerstone.

Asset Management Re-alignment (2007 to 2011)

In the current application, some of the functions in the Asset Management have been re-aligned compared to the previous distribution rate application EB-2009-0096. The changes in this application are outlined in Table 2 below:

Table 2
Asset Management Re-alignment - $M

	Historic 2007	Historic 2008	Historic 2009	Bridge 2010	Bridge 2011
Asset Management OM&A in EB-2009-0096	**93.8**	**100.3**	**120.4[6]**	**137.7**	**145.7**
Minus:					
Real Estate & Facilities [1]	(37.4)	(41.8)	(50.6)	(57.8)	(59.9)
Contract & Business Relations [2]	(5.1)	(4.9)	(5.1)	(6.2)	(6.3)
Groups from Business Integration transferred out of Asset Management:					
Outsourcing Services [3]	(1.2)	-	-	-	-
Information Asset [4]	(3.6)	(4.7)	(4.2)	-	-
Information System Support (half) [5]	(1.7)	(1.8)	(1.2)	-	-
Asset Management Cost Reductions[7]	-	-	-	(4.0)	(4.5)
Asset Management OMA in this Application	**44.8**	**47.1**	**59.3**	**69.7**	**74.9**

[1]Real Estate and Facilities cost for historic, bridge and test years was moved to Corporate Function and Services, see Exhibit C1, Tab 2, Schedule 6;

[2]Contract and Business Relations cost for historic, bridge and test years was moved to Operations, see Exhibit C1, Tab 2, Schedule 4;

Business Integration cost was adjusted downward to reflect the costs associated with certain groups leaving the Asset Management function as follows:

[3]Outsourcing Services cost of $1.2 million for 2007 was moved to Corporate Function and Services, see Exhibit C1, Tab 2, Schedule 6;

[4]Information Assets cost of $3.6 million in 2007, $4.7 million in 2008, and $4.2 million in 2009 was moved to Shared Services OM&A - Information Technology, see Exhibit C1, Tab 2, Schedule 9.

[5]A portion of Information System Support cost was moved to Shared Services OM&A - Information Technology, see Exhibit C1, Tab 2, Schedule 9.

[6] Note that the 2009 figure is an actual value as opposed to the year end forecast value presented in EB-2009-0096

[7] The cost reductions in the Asset management function of $4.0 million in 2010 and $4.5 million in 2011 represents hiring delays associated with the staffing level requirements to accomplish the planned sustaining, development, and operation work programs. The reductions are primarily driven by delays to elements of the work program..

2.0 STRATEGY AND BUSINESS DEVELOPMENT

Table 3 provides a summary of the Strategy and Business Development functions.

Table 3
Strategy and Business Development Functions ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Costs	5.9	6.3	7.5	11.2	12.5	13.0	3.5	3.7

2.1 Overview

This area consists of the strategy, conservation, business development and asset management costs and most of the activities in this function relates to Hydro One Distribution. Funding for property, boiler and machinery insurance costs is also included in this budget. The insurance amounts are $3.8 million in 2009, $3.9 million in 2010, $4.2 million in 2011 and $4.5 million in 2012.

2.2 Strategy, Conservation and Business Development Activities

The Strategy and Conservation function activities include:

- development and coordination of strategic plans for Hydro One transmission and Distribution businesses;
- initiation and coordination of Greener Choices program relating to internal energy efficiency for transmission and distribution;
- developing strategies that support corporate goals related to the Transmission and Distribution functions;
- assisting with improving industry efficiencies within the utility sector;

- overseeing the operation of the Customer Advisory Board for both transmission and distribution businesses;
- developing innovative conservation and demand management programs that meet the needs of Hydro One Networks' customer base;
- managing the design, development, and delivery of conservation and demand management customer programs funded by external agencies (such as the OPA or the Ministry of Energy and Infrastructure), for transmission and distribution customers.

Business Development activities include:

- planning and implementing business improvement initiatives (for example, smart networks);
- planning and implementing utility industry efficiency initiatives (for example, utility rationalization);
- supporting the development of opportunities to optimize leveraging of Hydro One Networks' assets (for example, secondary land use, utility rationalization, and utility boundary adjustments); and
- coordinating field activities, regulatory-driven activities (e.g. elimination of long-term load transfers) and programming of the transmission business.

3.0 SYSTEM INVESTMENT

The following Table 4 provides a summary of System Investment costs:

Table 4
System Investment Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Costs	**21.7**	**24.0**	**31.5**	**36.9**	**38.5**	**37.9**	**19.5**	**18.2**

3.1 Overview

System Investment develops and scopes transmission and distribution plans to address equipment performance, system reliability, compliance obligations, customer requests, OPA and government initiatives.

System Investment costs in test years 2011 and 2012 are increasing by 4% and 3% respectively compared to bridge year 2010. The cost increases are driven by the following:

- The increasing levels of transmission and distribution capital and OM&A sustainment and development work relating to the refurbishment and replacement of assets required to maintain the condition and reliability of assets, as well as implement improvements;
- Additional development of the Technical Interconnection Requirements for distributed generation and consultation with generators concerning the application of these requirements;
- Additional preparation of engineering protection and control specifications required to accommodate generators on a distribution system that was primarily design for load customers;
- Additional studies to determine the impacts of reverse flow on power equipment, as new local generation may exceed the load on a feeder which will result in power flows in the opposite direction to that designed;
- Development of P&C standards for transmission and distribution stations, and controllable elements. This level of complexity is new for the distribution system;
- An increase in the number of requests for generation applications, requiring

connection impact assessments;

- The need to develop new standards related to configurations or connections to the Transmission and Distribution networks;
- The need to develop, scope and obtain approvals for distribution plans in response to Government policy decisions related to the province's generation mix, in consultation with the OPA;
- The greater number and complexity of Section 92 and Environmental Approvals required for new facilities or expenditures;
- The need to ensure the processes are in place to comply with new industry standards and codes; and
- The significant involvement in the work initiation stage of the delivery chain for the growing levels of transmission and distribution capital and OM&A work programs.

3.2 System Investment Activities

System Investments activities include:

- Identifying, scoping and obtaining approval for projects and programs related to new and existing Transmission and Distribution assets. Such investments must meet defined needs in an economic and cost-efficient fashion, and be consistent with corporate objectives, regulatory requirements and government policy;
- Obtaining necessary approvals or endorsement of investment plans;
- Redirecting and re-prioritizing projects and programs in response to unforeseen events and work execution opportunities;
- Performing technical studies to assess the viability of proposed connections, alternatives or investment plans;

- Investigating power system disturbances;
- Conducting asset condition assessments;
- Monitoring and managing equipment and network performance;
- Establishing performance standards that establish the foundation for detailed engineering designs;
- Responding to customer requests for new or expanded connections or customer concerns regarding connection security or power quality;
- Advising external agencies and customers of the Transmission and Distribution impacts of their plans;
- Consulting with affected stakeholders regarding new Transmission and Distribution facilities;
- Participating in the development of North American or regional reliability standards;
- Supporting regulatory filings; and
- Specifying technical requirements and work in such areas as new technologies, animal abatement, transformer refurbishment (core heating) and remote monitoring.

4.0 Work Program Optimization

The following Table 5 provides a summary of Work Program Optimization costs:

Table 5
Work Program Optimization Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Costs	3.8	3.4	3.1	4.5	4.9	5.0	3.9	4.0

4.1 Overview

Work Program Optimization focuses on execution planning, integrating and bundling of awarded transmission and distribution work across Hydro One Networks. As shown in Table 5, the 2011 cost for this activity is $4.9 million with $3.9 million allocated to Transmission, and the 2012 cost is $5.0 million with $4.0 million allocated to Transmission. The cost increases in 2011 and 2012 over bridge year 2010 are due to the support requirements associated with the growth in the levels of transmission and distribution capital and OM&A sustainment and development work. Specific examples include the significant increases in Generation Connections. In addition to the direct connection work, there is a corresponding increase in work associated with making our transmission and distribution stations ready to accommodate more Distributed Generation connections.

4.2 Work Program Optimization Activities

Activities of the function include:

- Work Approval and Release – Administer the business case approval process and associated release of work to the services lines of business. Monitor and report the work release status and provide quality assurance of all work set-up.
- Work Execution Planning, Bundling & Integration - Work closely with functions across the organization to bundle and schedule work in ways that minimize outages, resources, schedule and costs. Lead cross functional teams to drive collaboration and continuously improve business processes.
- Develop work collaboration tools, systems and processes to drive continuous improvements across the corporation
- Resource Modeling – Determine overall resource needs for planned work and determine the impacts of outsourced work on internal staffing requirements.
- Quality Management- Develop and implement an Asset Management Quality Management System (QMS) that can be applied to projects/programs and strategic initiatives.
- Perform Quality Assurance Reviews of project/program work to verify performance levels, identify and implement improvements and facilitate monitoring and control of work quality
- Implement a Compliance Management System (CMS) to manage Regulatory (NERC/NPCC) and Business Compliance standards.

5.0 BUSINESS INTEGRATION

The following Table 6 provides a summary of Business Integration costs:

Table 6
Business Integration Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Costs	9.1	9.4	11.8	10.2	11.9	12.4	6.5	6.8

5.1 Overview

The Business Integration function integrates planning, budgeting, releasing, monitoring, reporting, and control of the growing capital and OM&A work programs and related processes for the major lines of business of Hydro One Networks, including Asset Management, Engineering and Construction Services ("E&CS"), Grid Operations and Customer Operations. As shown in Table 6, the 2011 cost for this activity is estimated at $11.9 million, with $6.5 million allocated to Transmission, and the 2012 cost is estimated at $12.4 million, with $6.8 million allocated to Transmission. Business Integration has experienced an increase in 2011 and 2012 compared to 2010 due to the support requirements associated with the growth in the levels of transmission and distribution capital and OM&A sustainment, development and operations work.

Additional costs will be incurred in both 2011 and 2012 to support the implementation and roll-out of the Cornerstone SAP project.

5.2 Business Integration Activities

Business Integration Activities include:

- Developing multi-year Hydro One Network Business Plans;
- Developing and leading the OM&A and capital Investment Planning process;
- Supporting regulatory processes, for Transmission and Distribution filings, within Asset Management;
- Performing business analytics and conducting special studies in such areas as productivity and cost savings management;
- Developing work program costing rates;
- Managing integrated processes for releasing and monitoring program results through common systems;
- Reporting and analyzing work program costs and results, and managing necessary program redirection;
- Reporting and analyzing Transmission and Distribution systems and component reliability;
- Developing and managing financial and customer reports;
- Managing corporate and line of business performance measurement and reporting processes;
- Performing detailed performance benchmarking and productivity studies in support of corporate objectives and regulatory filings;
- Managing distribution rationalization and Work Execution Program ("WEP") rollout and implementation; and
- Providing support to Cornerstone Phases 1, 2 and 3, and managing operational readiness of Phase 2 on behalf of Asset Management.

6.0 BUSINESS TRANSFORMATION

The following Table 7 provides a summary of Business Transformation costs:

Table 7
Business Transformation Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Costs	3.4	2.6	1.9	2.6	2.4	2.9	1.1	1.6

6.1 Overview

The Business Transformation function identifies emerging issues, develops appropriate responses, and implements selected time-limited initiatives that change the current operations of the Company and are critical to the future of Hydro One Networks Inc. Opportunities for improvement and especially projects that require an intensive, integrated approach across Hydro One Networks Inc. are a focus of this function. The total cost in 2011 for this function is $2.4 million, with $1.1 million allocated to Transmission and the cost for 2012 is $2.9 million, with $1.6 million allocated to Transmission.

6.2 Business Transformation Activities

Corporate Projects / Business Transformation Activities include:

- participating in the definition and scoping of cross-functional priority projects, or directly managing and mobilizing resources for large projects;
- managing cross-corporate initiatives to ensure an integrated approach to data, systems, and processes as well as contributing to change management within Hydro One; and

- managing Hydro One's integrated approach to Emergency Preparedness and Business continuity, including liaison with other industry organizations and various levels of governments;

Business Transformation's current priority is planning the replacement of a corporate core IT systems. The first phase, which went live on June 2, 2008, replaced the existing purchasing, inventory, work management, labour time entry, and Accounts Payable modules. The second phase of Cornerstone replaced the Financial, Human Resources and Pay systems; it was implemented in August 2009. (See Exhibit D1, Tab 3, Schedule 7 for further details on the Cornerstone project).

7.0 PROCESSES AND POLICIES

Table 8 provides a summary of Asset Management Processes and Policies costs:

Table 8
Asset Management Processes and Policies Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Costs	1.0	1.3	3.5	4.4	4.6	4.6	1.0	1.9

7.1 Overview

The Asset Management Processes and Policies Division (AMPP) strives to ensure the efficient and effective functioning of Asset Management and Hydro One through process improvement initiatives and tools; long-term transmission and distribution perspectives; leading-edge asset and system-related policies, strategies and procedures; regulatory support to Asset Management and Hydro One to ensure alignment with long-term corporate strategies; research and development activities; and liaison with external industry organizations, government and universities.

The budget for bridge year 2010 is $4.4 million, and the budget for 2011 and 2012 is $4.6M in each year.

7.2 Asset Management Processes and Policies Activities

Asset Management Processes and Policies activities include:

- Identifying, prioritizing and project-managing process improvement projects throughout Asset Management and the broader organization. Projects include seeking out and applying better approaches and tools in such areas as asset management analyses, strategy and risk management, data governance and change control, asset registry and asset condition assessment data, work execution, maintenance planning, and life cycle planning. Support is also provided for the planning and implementation of Cornerstone-related projects;
- Developing, reviewing and revising asset-related policies, strategies, and procedures for Hydro One;
- Contributing to work related to the smart grid project, including the ADS (Advanced Distribution Solution) initiative, and Hydro One's associated "Living Lab" in the Owen Sound and Walkerton areas;
- Providing regulatory support for Asset Management including evidence development for regulatory filings, expert witness support, and interrogatory response and undertaking preparation, and through preparing documentation and supporting the Section 92 Leave to Construct process for major transmission projects;
- Acting as a liaison with governmental agencies such as the OPA, ORF (Ontario Research Fund) and OCE (Ontario Centres of Excellence) on asset management matters, and research and development issues affecting the electricity industry. AMPP staff also contribute to the development of OPA-initiated long-term supply studies and provide coordination as required;

- Providing expert participation in, and representing Hydro One's interests on, various national and international industry entities and standard-setting bodies including CIGRE, CEA, CEATI, IEEE, NERC, NPCC, the North American Transmission Forum, NIST, and the IESO. For example, AMPP staff participate in reliability standards development and compliance monitoring with NERC and the NPCC, and its staff also represents Canada at the International Electrotechnical Commission (IEC). In addition, AMPP staff serve as the transmitter representative on the Independent Electricity System Operator ("IESO") Technical Panel, which reviews and recommends amendments to the Ontario wholesale electricity market rules, and advises the IESO Board of Directors on specific technical issues related to the operation of the Ontario Electricity Market;.
- Having the overall responsibility of monitoring and advising Hydro One's business units on reliability standards compliance obligations as stated in our license and in the market rules, and coordinating compliance activities;
- Providing the longer-term perspectives for Transmission and Distribution facilities in terms of sustainment, development, and operating work programs;
- Managing or contributing to research and development in such areas as smart grid, electrical vehicles, and distributed generation, through industry and research organizations (e.g. EPRI and CEATI) and Ontario universities
- Liaising with Ontario universities with an electrical or power-systems engineering focus.

SHARED SERVICES OM&A - INFORMATION TECHNOLOGY

1.0 OVERVIEW

Information Technology (“IT”) refers to computer systems (hardware, software and applications), data and voice communication systems that support business processes and allow employees to perform work activities.

IT work programs include both OM&A and capital items and include the ongoing maintenance and sustainment of existing and newly commissioned applications and technologies; the development and implementation of new technologies or systems; the provision of Business Telecom services; and the overall management and control of the information technology program – including capital projects. IT capital investments are made in accordance with approved business strategies and are described in Exhibit D1, Tab 3, Schedule 6.

OM&A costs associated with supporting Hydro One’s information technology assets are shown in Table 1 and are described below.

Table 1
Information Technology Summary of OM&A Expenditures
($ Millions)

Description	**Historic**			**Bridge**	**Test**		**TX Allocation**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2011**	**2012**
Sustainment	63.9	72.4	81.9	90.0	90.8	92.5	39.0	39.6
Development	6.0	2.8	3.5	10.8	8.4	8.6	3.5	3.6
Business Telecom	17.2	17.2	20.8	21.2	23.4	23.6	12.2	12.3
IT Management & Project Control	12.0[1]	16.3[2]	22.5[3]	25.5	25.5	25.8	12.8	13.0
Total Cost	**99.1**	**108.7**	**128.7**	**147.5**	**148.1**	**150.5**	**67.5**	**68.5**

[1]Information Assets department and ISS group not included in IT Management in 2007.
[2]Partial year of amalgamation of IT resources from the Enablement, Information Assets department and ISS group.
[3]Full year of amalgamation of IT resources from the Enablement, Information Assets department and ISS group.

Sustainment costs are paid to Inergi LLP ("Inergi") pursuant to the Outsourcing Contract. March 1, 2010 marks the start of year 9 of the 10 + 3 year contract. As of May 2010, a 3 year extension was negotiated to take the outsourced services with Inergi to March 2015. Sustainment costs are costs to support the Hydro One information technology applications and infrastructure.

Starting in 2010, sustainment costs represent full year costs of supporting the solutions delivered by the Cornerstone Phase 1 and Phase 2 projects. When projects are "in-service" the costs to sustain the applications are included in Sustainment costs. Additional incremental costs are attributed to growth in license costs as well as incremental data storage costs.

IT Development includes non-capital business improvement and enhancement work within SAP and ancillary systems including associated business processes. Expenditures include keeping the core systems within the vendors' upgrade path as well as highlighting business improvement areas through enhanced analytics and reporting.

Business Telecom costs include data and voice telecommunications and associated maintenance of Hydro One's telecom network. Changes in costs vary with the number of offices, their locations and the size of Hydro One's workforce.

IT Management and Project Control costs relate to IT administration, project oversight and reporting, program and spend coordination, and Quality Assurance ("QA")/Quality Control ("QC") processes.

Technology costs are subject to an IT governance process at Hydro One. IT Governance looks proactively at IT strategy, project expenditures and service delivery to align technology spend with business and corporate objectives.

The IT governance model involves the senior business managers who provide guidance, direction and support to the decision-making for corporate technology decisions. The Line of Business executives act as an IT Steering Committee to which the CIO reports to at regular intervals ensuring alignment between business needs and technology solutions. The Steering Committee's mandate is to review and prioritize IT investments on a corporate enterprise basis.

2.0 IT SUSTAINMENT OM&A

Table 2 shows the specific expenditures for IT sustainment of the Information Technology infrastructure.

Table 2
OM&A Sustainment of Information Technology
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Base IT Sustainment Services	43.5	51.4	49.7	52.7	51.2	50.6	22.5	22.1
OMS Incremental Sustainment	6.5	6.2	6.0	6.1	5.3	5.1	1.1	1.0
Other Incremental Sustainment	13.9	14.8	26.2	31.2	34.3	36.8	15.4	16.5
Total	**63.9**	**72.4**	**81.9**	**90.0**	**90.8**	**92.5**	**39.0**	**39.6**

IT OM&A Sustainment work includes help desk and desk side support; implementing system patches; applying fixes for application, resolving application problems; security patching; decommissioning or installing software applications or equipment; maintaining and operating Hydro One IT assets located at offices and the data centres; and data storage capacity and data storage management.

Sustainment OM&A costs also include amounts which are paid to third parties for software licenses and annual maintenance fees.

IT sustainment work is broken down into the three categories discussed below.

2.1 Base IT Sustainment Services

The term "Base" IT Sustainment Services refers to those IT services, including the sustainment services discussed above, that were part of the original scope of work outsourced in March, 2002 to Inergi and which are scheduled in the negotiated contract.

Base IT services include charges for Inergi pension costs (approximately $1.5 million each year) and the Base IT costs are adjusted for Cost of Living changes (COLA).

The COLA factor is "based upon the Statistics Canada Indices of total wages, salaries, and supplementary labour income in Ontario, and total number of employees in Ontario" and uses 2001 as a base year. The COLA factor for each year is calculated by comparing the annual Statistics Canada Indices for that year with the 2001 values.

In 2010, the COLA cost factor is $13.5 million. In 2011 it is estimated at $14.3 million and in 2012 at $14.9 million.

Base IT services are discussed under the five categories below.

Hardware Maintenance/Software License Fees

Application software license costs and maintenance fees are costs paid to third party vendors for software applications which are used by Hydro One.

At the inception of the outsourcing agreement $13.4 million of application costs were transferred to Inergi to administer on a pass through basis. Over time many of these contracts have migrated back to Hydro One, and are now administered (managed) by Hydro One. Contract costs which are now being managed by Hydro One, and administered by Inergi, are reflected in Other Incremental Sustainment costs.

License or maintenance agreements are usually subject to annual increases as part of the contractual terms with the vendor. These fees are subject to annual audits by the third party vendors to confirm the fees match the services provided.

Application Maintenance

Application maintenance includes the work to maintain, address and fix matters associated with approximately 970 Hydro One software applications used by the various business units across the Province. Within these applications there are strategic or business critical software applications used in major functional areas, such as those shown in Table 3, which support business processes across the enterprise.

Based on support levels established by IT and the respective business operations, applications are managed in a problem management framework. Application problems and user inquiries are logged, prioritized, and managed through to resolution.

Table 3
Strategic Information Technology Systems

IT Systems	**Description**
Desktop Applications	These include Microsoft Office XP/2003 (for example, Word, Excel, Access, and PowerPoint), e-mail, Internet browser, and various other applications such as anti-virus and directory functions. Hydro One's e-mail system processes approximately 80,000 e-mails per day.
SAP™	This is an integrated enterprise asset management (EAM) application suite that provides Asset and Work Management, Purchasing and Supply Chain functions as well as Inventory Management functions. The application was implemented through a series of phases which saw it replace the Peoplesoft application in 2009. This Financial and HR application suite now provides General Ledger, Accounts Receivable, Fixed Assets, Project Accounting, Payroll, and Pension functions. In order to be compliant with Federal Tax regulations Hydro One is required to retain the Passport application as a reference application for the next 7 years. Some support costs are required to maintain the Passport system and the related database to be compliant with regulatory requirements.
Customer Information System	The CIS is an application suite providing billing and services support through sub-systems of Customer Service System (CSS) and Open Market Systems that interface with each other. The CIS application is also scheduled for replacement under the Cornerstone Program though no replacement application has been selected. Timing of the application replacement is partially dependent on the timing and implementation of Smart Metering.
Contact Centre Technology	This suite of applications enables contact centre operators to respond to customers (service requests, billing inquiries, information), including telephony interfaces and call centre technology and provides operators scheduling and service quality-monitoring functions.
Open Market Systems (OMS)	These are a set of applications that provide for meter data collection, sending/receiving of electronic business transactions with market participants, bill calculations, and settlement functions with the Independent Electricity System Operator.
Field Design Tool (ArcFM)	This is a geographic application that is used to design and modify customer connections to the electrical distribution system.
Work Execution Project (WEP)	WEP consists of 3 applications (Pragma CAD, P3e,e-time) which are used to plan, schedule, dispatch and report on work completion. The applications are used for work planning, crew scheduling and for both planned and unplanned field work. The applications are "out of the box" and are cross linked to ArcFM, SAP and to Customer One through the use of the enterprise bus or enterprise middleware.

Data Centre Services

Data centre services include the operations, maintenance, and management of hardware (servers, mainframe, storage area network and data storage devices), operating systems, associated applications and infrastructure located at the data centre facilities. This hardware is used to run enterprise business applications, noted above, that are critical to operating the business.

Data Centre service levels have been established to ensure the reliable operation of business applications and are based on system criticality. The system hardware is located at production and backup data centres, which have the required system redundancies including 24/7 monitoring. Hydro One utilizes the backup data centre facility as a Disaster Recovery site in the case it is unable to operate from its production data centre.

Distributed Server Sustainment

Distributed server sustainment includes the support services that maintain and operate the application and file servers that are located at various Hydro One facilities across the province. The servers are used to run business applications and administration systems such as file sharing, e-mail exchange, web hosting and security monitoring systems. This work is required to maintain the reliability of the servers and the business applications supporting business operations.

Help-Desk & Desktop Support

Help-Desk and Desktop Support includes daily and emergency IT maintenance services delivered to employees across the Province.

The support function is provided through two key service areas: the Help Desk which provides centralized call handling through a 1-800 number and through e-mail; problem resolution and escalation or referral for all IT and telecom service areas; and Desktop Workstation Support which provides physical desk side support to fix hardware and software problems for laptops, desktops and rugged tablet computers. Desktop Workstation Support includes the support for IT peripherals such as printers, plotters, scanners and other equipment. Help Desk support includes work comprising a number of functions including handling trouble calls, trouble or requested service e-mails, providing application support and resetting or enabling application or system passwords.

Desktop and Help Desk support is available to all users across the province and assistance can be provided by telephone, remotely through the data network, or if necessary through the use of Inergi field technicians. On a monthly basis, approximately 8,000 (2009 monthly average) help desk calls are logged, dealt with and cleared. Effective and timely response to these calls ensures the efficient operation of the technology infrastructure which enables Hydro One staff to perform their work unimpeded.

2.2 Open Market Systems ("OMS") Incremental Sustainment

This category is incremental to the base sustainment identified and was sourced to Inergi in 2002. Specifically, the workconsists of the support functions performed to sustain the OMS hardware and software applications. The OMS is comprised of a suite of software applications that have been bundled together to provide the required functionality using service oriented architecture and middleware applications. The support for the OMS was contractually "locked in" and is supported by Inergi at an annual cost of $6.1 million in 2010, $5.3 million in 2011, and $5.1 million in 2012. The OMS suite is used to enable wholesale and retail settlement processes. The processes provide interaction with the

IESO and other market participants and are required for the business to operate under the Province's open market policies, driven in part by the *Electricity Act, 1998* and related legislative policies.

2.3 Other Incremental Sustainment

Other Incremental Sustainment includes additional sustainment services provided in order to support and manage business applications, commissioned since March, 2002. These costs include license and software costs (which have transferred to Hydro One as noted earlier in Section 2.1), new services, as well as volumetric changes in service levels due to staff growth and new business requirements.

New applications are being continually commissioned or added to meet evolving business requirements. Additionally, service levels increase as demand for services increase. Contractually, Hydro One is required to pay for these increased service levels and is required to purchase revised volumes ("lock in") when service level demand meets specific volumes. Since 2002, the incremental sustainment cost has increased as additional applications have been added annually through capital projects, such as Cornerstone, and also through development projects.

In 2009 Other Incremental Sustainment totaled $26.2 million and consisted of $6.5 million for SAP application support, $0.9 million for support of other applications, and $18.8 million for third party license and maintenance contracts.

In 2010 Other Incremental Sustainment will total $31.2 million. SAP application support will increase to $9 million to accommodate a full year of support for the phase 2 rollout of SAP, and support of other applications will remain at $0.9 million. Third party license and maintenance contracts will increase to $21.3 million due to increased Microsoft licensing fees, SAP software maintenance (previous years were included in the software purchase price), and other license and maintenance fees.

In 2011 Other Incremental Sustainment will total $34.3 million. SAP application support will remain at $9 million and support of other applications will remain at $0.9 million. In 2011 Smart Metering application support costs of $1.5 million will be transferred from the line of business to Other Incremental Sustainment. Third party contracts will increase to $22.9 million, primarily due to increased usage of Microsoft tools (Office Communicator, Sharepoint, LiveMeeting) and a related increase in Microsoft licensing costs.

In 2012 Other Incremental Sustainment will total $36.8 million. SAP application support will increase to $9.6 million due to added functions/modules, Smart Metering application support will increase to $1.6 million, and the support of other applications, like the Mobile IT platform, will increase to $1.1 million. Third party contracts will increase to $24.4 million, primarily due to increased Microsoft licensing costs and added Microsoft product usage.

A list of planned incremental capital projects, excluding Cornerstone, which in turn will create incremental sustainment needs when these projects are commissioned, is found in Exhibit D1, Tab 3, Schedule 6.

3.0 IT DEVELOPMENT OM&A

Table 4 lists the expenditures driven by non-Capital small IT projects and the OM&A portions of capital projects.

Table 4
OM&A Development Expenditures
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Small Projects	5.6	2.7	3.5	10.8	8.3	8.5	3.5	3.6
Impact of Capital Projects	0.3	0.1	0.0	0.0	0.1	0.1	0.0	0.0
Total	**6.0**	**2.8**	**3.5**	**10.8**	**8.4**	**8.6**	**3.5**	**3.6**

3.1 Small Projects

Small project costs for 2011 include application rationalization, upgrades to the Arc FM GIS application and enhancements to workflow and the customer relationship management systems in support of Distributed Generation connections. Also included are changes to the customer information and billing system. Additional expenditures for 2011 include the continuation of business driven application enhancements and ensuring that the environment remains current and continues to provide adequate function for evolving business requirements.

With the transfer of the Enablement organization from Finance into IT, their business improvement and enhancement work program is added to this category as of 2010. The work is similar to small projects with a focus on leveraging SAP assets and ancillary systems to their full potential including associated business processes, data and interfaces.

Expenditures for 2010 and 2011 include: enhancements to enterprise analytics and reporting by further leveraging SAP Business Intelligence/Business Warehouse (BI/BW); performance management improvements through the development of key performance indicators (KPI’s) for SAP enabled processes; and improvements to work management and supply chain processes and system interfaces to those processes. Also included are planned upgrades to SAP modules to ensure that they remain current and vendor supported

For 2012, many of the multi-year initiatives previously mentioned will continue to move forward such as application portfolio management/rationalization, upgrades to the GIS application, business driven enhancements to applications and processes and changes to the customer information system. 2012 costs associated to SAP and ancillary systems include: reporting and analytic enhancements, process and performance improvements, the migration of legacy applications to SAP and planned upgrades to SAP modules to ensure that they remain current and vendor supported.

The number of small projects and the associated small project costs varies each year depending on the work projects requested by the lines of business to meet their needs and programs. Small projects costs and programs are reviewed with the IT steering committee on a regular basis.

3.2 Impact of Capital Projects

"Impact of Capital Projects" includes business process re-engineering costs such as training and change management work efforts that are required to implement and train the line of business personnel when new or revised IT applications are introduced. These costs are associated with the IT capital projects discussed under Exhibit D1, Tab 3, Schedule 6 and typically reflect an OM&A cost equal to 10% of the Capital project.

In accordance with Hydro One's accounting practices, the cost associated with this implementation work (training and business process change) is not capitalized. The implementation work ensures each new business application or upgrade is properly introduced and has the necessary user understanding and support.

4.0 BUSINESS TELECOM

Business Telecom provides the data and voice telecommunications services, network operations management and field service repairs which are required for the company to operate from its province-wide locations. The business telecommunications data network is comprised of a mixture of company owned and leased facilities and equipment. Costs incurred in this area are primarily costs for third party services.

Table 5
Business Telecom OM&A Expenditures
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Operations and Carrier Management	4.2	4.4	4.8	5.0	5.9	6.2	3.1	3.2
Field Services	3.8	2.7*	5.3	3.5	3.7	3.2	1.9	1.7
Voices Services	4.1	4.7	5.7	5.8	6.3	6.3	3.3	3.3
Data Network Services	5.1	5.4	5.0	6.9	7.5	7.9	3.9	4.1
Total	**17.2**	**17.2**	**20.8**	**21.2**	**23.4**	**23.6**	**12.2**	**12.3**

***** The 2008 Field Services cost was lower than planned because of a one time cost reduction initiative as a result of triggering service credits, telecom asset cleanup and realization of service discounts with Bell Canada.

4.1 Operations and Carrier Management

Operations and Carrier Management costs relate to telecommunications management services provided by Hydro One Telecom. Hydro One Telecom ("HOT") provides both power system telecommunications monitoring and network operations monitoring for the power system and the business operations of Hydro One. Costs reflected in Operations and Carrier Management reflect the contracted costs with HOT to provide Hydro One with telecommunication management services and operations oversight and control for its business operations. The affiliate agreement is found in Exhibit A, Tab 7, Schedule 3.

In 2005 an independent industry review concluded that the service level agreement for the Hydro One Telecom operation centre, and for the services provided by it, reflects market conditions and that Hydro One Telecom has provided an advantage to Hydro One in respect of telecom administration and the resultant costs. The study also concluded there are unique requirements for operating the telecommunication system of an electric utility which are not easily delivered through a third party non-electric utility carrier.

In 2006 and 2008, updated independent assessments were undertaken by The Shpigler Group to benchmark the costs of services being provided by Hydro One Telecom. The assessment process included looking at the contracts and statement of work for services to be covered in the regulatory review period. The reports considered the revised services which will be performed in the years covered and the costs to be charged by Hydro One Telecom in providing those services.

Consistent with the opinion provided in earlier studies undertaken, the 2008 study states: "In our opinion, the unique voltage potential of a power system has created the need for electric utilities to create their own telecommunications entities that can isolate and insulate the telecommunication infrastructure, which protects communications during electrical disturbances. Protecting electrical equipment requires sophisticated systems that need to communicate between substations and power plants. The need to isolate electrical and telecommunications facilities for safety and service reliability has supported the development of large utility telecommunication entities. Even with fiber optic channels negating some interfacing concerns, the need for end electronics equipment to interface with optical equipment at risk to voltage surges still exists. Network operation centers of public and private telecommunications companies rarely have the experience or knowledge necessary to manage a power systems telecommunication system. Therefore, for benchmarking purposes, we determined that the most meaningful and comparative data would need to be obtained from similar Canadian utility telecommunication entities."

The report concluded the contracted costs are indicative of fair market value. The reports reaffirmed the conclusion that Hydro One obtains commercial and operations benefit through its relationship with Hydro One Telecom. These costs were deemed acceptable by the Board in the EB-2008-0272 Transmission proceedings.

The increase in 2012 costs represents the anticipated commissioning and ongoing support of IT security monitoring services that supplement the existing telecom operations and monitoring services.

Work performed by Hydro One Telecom includes operating and monitoring the business telecom and data networks, management of security firewalls, security patching, management of network interfaces with third parties, spam control, managing data and voice system problems, obtaining and managing fibre services from third party vendors, and directing other telecom service providers and vendors to change, maintain, and restore the networks as required. On an ongoing basis, this function includes managing third party supplier contracts as well as analyzing and processing bill payments to 3rd party common carriers and other telecom service providers.

Telecom service firms who provide fibre and network access include common carriers such as Bell Canada, Telus and MTS/Allstream. These companies lease telecom data and voice circuits to Hydro One at competitive market rates. The management of these services requires the contracted services of Hydro One Telecom to proactively liaise with the many common carriers in Ontario and other service suppliers.

Operations and Carrier Management also provides oversight of the Bell Field Services contract as described below.

4.2 Field Services

Field Services includes the maintenance and repair of voice and data telecom equipment. Field Services also includes the handling of connection changes for moves, additions, changes, and deletions ("MACDs"). Since 2004 this work has been outsourced to Bell Canada after a competitive process. In 2008, service credits, telecom asset cleanup and realization of service discounts were triggered as part of the contract. The result was lower than anticipated Field Services costs in 2008.

The year-over-year costs for Field Services is due to staff movements (move/add/changes to voice and data telecom configuration) as well as introduction new sites.
2009 Field Services impacts:

- Additional floor space at 95 Mural for project office
- Newmarket Garage
- South Tower 483 Bay (trinity floor 4 and 6)

Through another competitive tendering process in 2009 where a new services contract was awarded to Bell Canada, costs in 2010 to 2012 will be lower than the costs paid for those services from previous years. This is counter-balanced by increased costs to accommodate staff additions and relocations in support of the capital work program.

The MACD agreement calls for Bell Canada technicians to be dispatched across the province to resolve any telecommunications issues. These include MACDs and preventive maintenance at any of the Hydro One sites across the entire Province.

Selected Bell Canada staff has been specifically trained to work at the Hydro One sites and facilities and to work safely in a high voltage environment.

4.3 Voice Services

Voice Services investments consist of payments made to common carriers and vendors to use and lease voice circuits and equipment. Rates charged by common carriers are competitive. Voice Services include monthly charges, usage fees and equipment rentals for voice grade business telecom (local and long distance). The local voice service rates are regulated under CRTC. Long distance rates were secured using a competitive bid process. Annual costs are volumetric and usage-based.

4.4 Data Network Services

Data Network Services investments consist of payments made to third party common carriers such as Bell, MTS/Allstream, and Telus to lease data network circuits and equipment at market rates. The data network is used to connect servers and computers across the province for software applications.

Hydro One continues to monitor and upgrade band width as applications are deployed to field offices in order to support business processes and business requirements.

While network capacity grows each year to accommodate sharing more data among more functions, to address increases in office size and to address connectivity requirements from distributed enterprise applications, the Company has maintained cost control on data network components. Downward cost pressure is maintained through investments in efficient up-to-date IT hardware and by ensuring a competitive process for services.

Data Network Services costs increases follow the same trend as the Voice Services because of the change of existing sites or the addition of new sites.

5.0 IT MANAGEMENT & PROJECT CONTROL

Table 6 lists the associated costs for IT Management and for Project Support and Control.

Table 6
IT Management & Project Control Expenditures
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
IT Management	10.9	13.2	18.1	19.0	20.0	20.5	10.4	10.7
Project Support and Control	1.1	3.1	4.4	6.5	5.5	5.3	2.4	2.3
Total	**12.0[1]**	**16.3[2]**	**22.5[3]**	**25.5**	**25.5**	**25.8**	**12.8**	**13.0**

[1] Information Assets department and ISS group not included in IT Management in 2007.
[2] Partial year of amalgamation of IT resources from the Enablement, Information Assets department and ISS group.
[3] Full year of amalgamation of IT resources from the Enablement, Information Assets department and ISS group.

To manage the overall IT program and as the enabler and controller of IT projects, IT Management and Project Support and Control develops and implements IT strategies, policies and processes along with IT architectural standards for application interoperability, infrastructure capacity, network security, regulatory compliance and IT governance, and telecom capabilities and communications security. Within the scope of these costs is work associated with hardware procurement, training, detailing vendor responsibilities, architecture development, and research services that are required to match IT solutions to known business needs and opportunities. Work performed also includes keeping current on industry trends, product innovations, technology changes in infrastructure and applications, research, as well as planning for future investments.

IT Management includes the cost to coordinate, manage and plan the extensive IT infrastructure, to manage the daily issues around IT outsourced services, and to oversee projects. IT Management performs work covered through needs assessment, business case preparation, planning, development, and service delivery to the lines of business.

Projects or programs that the IT Management and Project Support and Control will manage or deliver in 2011 and 2012 include Mobile IT, development and application migration; architectural design and compliance policies (particularly around SAP); application rationalization; data architecture and data management; updating IT policies and technology roadmaps; Bill 198 compliance; ongoing security requirements and enhancements including documentation, training and testing; negotiation of contracts; supporting hardware purchases for major projects and for growth; supporting the outsourcing optimization process with Inergi; implementation of the Enterprise Content Management project for record retention; and selection and implementation of more self service products for end users. In addition to the above, project support and control functions will provide QA/QC review and compliance verification on 3rd party work.

Expenditures include the formation of the Enablement department into IT from Finance starting mid way through 2008. Enablement costs in 2011 and 2012 are estimated at $7.9 million and $8.1 million respectively. Year-over year increases are to support new enterprise application functions as they are configured and commissioned.

The Enablement group is the corporate owner for the SAP application and they are accountable for process and data management, performance improvement, and training and business solutions related to the systems and processes implemented by the various phases of the Cornerstone program. The Enablement group supports the organization in the effective and efficient use of the SAP system.

The Enablement group will drive productivity through enterprise process improvements and will ensure Hydro One leverages and consolidates legacy applications into SAP and associated systems. This will include adding new functionality where it delivers increased end user productivity, quality of work, and other measurable business improvements. It will also govern data as an asset and drive better analysis and decision making. The costs include staff and other expenses to provide technical expertise, business analysis, problem solving, governance, and continuous improvement to deliver these accountabilities.

SHARED SERVICES OM&A – CORNERSTONE

Table 1 below identifies the OM&A expenditures and savings for the Cornerstone project for the period 2007 to 2012.

Table 1
Cornerstone ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Development	4.8	2.6	7.1	1.6	1.8	2.2	1.0	1.2
Savings	-	-	*	(15.6)	(19.7)	(31.3)	(13.5)	(22.7)
Net	4.8	2.6	7.1	(14.0)	(17.9)	(29.1)	(12.5)	(21.5)

* $9.6 million in savings realized in 2009

1.0 OVERVIEW

The Cornerstone Project is part of the overall information technology ("IT") strategy to replace several of Hydro One's key enterprise information systems as they reach their 'end of life'. The Cornerstone Project is also a major business process transformation initiative that provides a platform for further effectiveness and efficiency gains at Hydro One. A detailed description of the Cornerstone project is provided in Exhibit D1, Tab 3, Schedule 7. This exhibit presents the OM&A development costs of Cornerstone, the forecast OM&A process improvement savings and the result of netting these savings against the development costs. Costs for sustaining the new systems resulting from the Cornerstone implementation are included in Exhibits C1, Tab 2, Schedule 9. Costs for supporting the new processes resulting from the Cornerstone implementation are included in Exhibits C1, Tab 2, Schedule 7.

2.0 DEVELOPMENT

OM&A development expenditures for Cornerstone include such costs as initial investigation and retirement of the end of life IT.

The differences in year to year expenditures are the result of the phasing of Cornerstone implementation.

3.0 SAVINGS

Savings arising from the introduction of Cornerstone are the result of improved processes. These saving are re-invested in Hydro One's business. Savings occur following the implementation and break-in period of the new Cornerstone systems.

A description of the savings is provided in Exhibit D1, Tab 3, Schedule 7.

Savings significantly increase from 2010 to 2012 as process improvements from Cornerstone are leveraged in the business.

SHARED SERVICES OM&A - COST OF SALES – EXTERNAL WORK

1.0 OVERVIEW

Hydro One Transmission directly tracks cost of sales for unregulated revenues, which includes Station Maintenance activities, Engineering and Construction work. These are competitive services requested by customers and are individually priced. Exhibit E1, Tab 1, Schedule 2 describes the categories of external business and associated revenues over the 2007 to 2012 period, which also relates to the level of external costs.

Hydro One Transmission does not directly track costs for all its unregulated service revenues of Secondary Land Use and Other External Revenues. These costs are embedded in the Company's shared services costs.

The cost of sales for the 2007 to 2012 period is provided below.

Table 1
Cost of Sales – Transmission External Work ($ Millions)

Description	2007 Historic	2008 Historic	2009 Historic	2010 Bridge	2011 Test	2012 Test
Station Maintenance	9.8	11.0	9.7	4.9	4.0	2.6
Engineering & Construction	4.7	9.5	2.9	10.4	10.4	5.4
Other	0.0	0.0	1.2	0.5	0.5	0.5
Totals	**14.5**	**20.5**	**13.5**	**15.8**	**14.9**	**8.5**

The 2007 to 2012 costs are consistent with the drivers identified in Exhibit E1, Tab 1, Schedule 2, except for Secondary Land Use, Inergi Royalties and a portion of Other External Work.

The costing of external work is calculated the same way as for internal work as described in Exhibit E1, Tab 1, Schedule 2 and Exhibit C1, Tab 4, Schedule 1.

2.0 STATION MAINTENANCE

Cost for Station Maintenance is directly related to the volume of work performed by Hydro One Transmission to support Ontario's key generating suppliers: Bruce Power LLP, OPGI and Siemens Westinghouse Inc. The decrease in 2011 and 2012 costs reflect the planned shift in resources towards Hydro One Transmission's growing work program.

3.0 ENGINEERING AND CONSTRUCTION

Cost for Engineering & Construction is directly related to the volume of work performed by Hydro One Transmission for the upgrading of revenue meters at various sites within the province per IESO requirements. The costs for historic, bridge and test years are outlined in Table 1. The costs for 2011 and 2012 are forecasted at $10.4 and $5.4 million respectively, resulting from the planned levels of revenue metering activities.

4.0 OTHER

Cost for other represents the forecast for work related to Hydro One other entities. See the Affiliate Service Agreement in Exhibit A, Tab 7, Schedule 3, and External Revenues in Exhibit E1, Tab 1, Schedule 2.

CUSTOMER CARE OM&A

Table 1 provides a summary of Customer Care costs:

Table 1
Customer Care Work Program ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2011**	**2012**
Customer Care Services	91.7	93.9	101.7	95.5	90.1	89.4	0.6	0.6
Customer Care Mgmt	6.6	6.7	7.7	11.8	13.3	14.0	0.5	0.6
Total Cost	**98.3**	**100.6**	**109.4**	**107.3**	**103.5**	**103.4**	**1.1**	**1.2**

1.0 OVERVIEW

The Customer Care OM&A Work Program represents the set of work activities required to provide customer care services to the almost 1.2 million customers connected to the Hydro One Transmission and Distribution Systems. The main Customer Care service programs are meter reading, billing, settlements, customer contact handling and collections.

The majority of Customer Care costs were reviewed during Hydro One's application for 2010 and 2011 electricity distribution rates, EB-2009-0096, for which a decision is pending from the Ontario Energy Board.

A small amount of the Customer Care Work Program budget is allocated to Hydro One Transmission, as identified in Table 1 above. Customer Care costs allocated to Transmission in 2011 and 2012 are consistent over the test years. A description of the transmission-related work follows.

2.0 CUSTOMER CARE SERVICES

Customer Care Services costs allocated to Transmission of $0.6 million in 2011 and $0.6 million in 2012 relate primarily to the settlements function activities.

The Settlements function ensures the integrity of financial transactions between Hydro One, the IESO, and applicable transmission-connected customers. Transmission-related settlements activities include:

- Calculation of gross load billed quantities at specific delivery points and submission to the IESO
- Reconciling transmission delivery point quantities and charges, and allocation of transmission pool revenues according to Ontario Energy Board approved allocations,
- Identifying anomalies and exceptions in metering data used by the IESO to bill Hydro One transmission-connected customers.

3.0 CUSTOMER CARE MANAGEMENT

The Customer Care Management function is accountable for customer policy, planning, work program budgeting, service performance management, settlement services, customer research, project management and responding to escalated customer complaints. The function is also accountable for policy, planning, account and payment management for distributed generation customers.

Customer Care Management costs are considered Common Costs, and are included in the corporate cost allocation method for Common Costs.

The time allocation study completed in 2009 identified four per cent of Customer Care's time as attributable to transmission. This allocates $0.5 million in 2011 and 0.6 million in 2012, and represents the following transmission-related work:

- Specifying appropriate transmission tariffs to be applied by the IESO for each transmission delivery point per the corresponding Transmission Connection Agreement,
- Updating, reviewing and approving transmission totalization tables plus related IESO transmission delivery point site registration reports, meter connectivity and wholesale meter registration information for each transmission delivery point,
- Identifying transmission tariff gross-load billing for specific transmission delivery points as a result of the connection of non-renewable and renewable generators; and
- Customer surveying and research of transmission-connected Hydro One customers.

PROPERTY TAXES

1.0 A SUMMARY OF TAXES OTHER THAN INCOME TAX

A summary of taxes other than income and capital taxes is presented below:

Table 1 ($ Millions)

Description	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Property Tax	55.2	57.6	58.3	60.4	61.8	63.2
Indemnity Payment	4.5	4.5	4.5	4.5	4.5	4.5
Rights Payment	2.8	2.7	2.4	4.5	4.5	4.5
Total	**62.5**	**64.8**	**65.2**	**69.4**	**70.8**	**72.2**

Property Tax and Rights Payments funding levels generally reflect higher tax rates, increases in the assessed value of Hydro One properties and increases in land values.

2.0 PROPERTY TAX

Hydro One Transmission, like every other land owner within the Province of Ontario, is responsible for the payment of property taxes. Property taxes for Hydro One are regulated under the Electricity Act 1998, the Municipal Act 2001, and the Assessment Act 1990. Property taxes are levied on Hydro One Transmission's land and buildings, including service centre sites, transmission stations and transmission lines. Hydro One Transmission pays property tax to about 400 municipalities each year.

A summary of annual transmission property taxes is presented in Table 2, below:

Table 2
Breakdown of Property Tax Expense ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Stations and buildings, including proxy tax	16.4	16.1	16.7	17.8	18.9	19.7
Transmission lines	38.0	40.5	40.6	41.4	41.6	42.1
Other	0.8	1.0	1.0	1.2	1.3	1.4
Property Tax Total	**55.2**	**57.6**	**58.3**	**60.4**	**61.8**	**63.2**

2.1 Transmission Stations and Buildings

For municipal property tax purposes, transmission station buildings are assessed at a statutory rate of $86.11 per square metre, according to the Assessment Act R.S.O. 1990, Chapter A31, Section 19. The lands containing the transmission stations are assessed using the Current Value Assessment ("CVA") method -- the valuation method used for other property owners within the Province. Hydro One Transmission property other than transmission lines and not classified as a transmission station (for example, a service centre), is assessed using only the CVA method. The Municipal Property Assessment Corporation assigns the total assessed value, which is updated utilizing the same schedule as for the rest of the Province. Provincial reassessment was issued for 2009 tax year, the next scheduled province wide assessment is 2012. Under the Assessment Act, an increase in assessed value between January 1, 2005 and January 1, 2008 is phased in over four years, from 2009 to 2012, assuming the property characteristics and assessment evaluation stays the same.

Notices of Assessment are received and reviewed for accurate valuation and tax classification each year. Any incorrect classes and/or over-valuations are appealed through the Municipal Property Assessment Corporation, and/or the Assessment Review Board.

Additional property tax payments, called proxy property taxes, for owned transmission stations are levied and paid to the Minister of Finance, to be applied against the stranded debt of the former Ontario Hydro. The details of this additional assessment are contained within Ontario Regulation 224/00 under the Electricity Act, 1998. The additional tax is the difference between the statutory rate for transmission station buildings and the municipal tax that would apply to the buildings if they were taxed using the CVA method. This amount is calculated each year for each transmission station owned by Hydro One Transmission.

Ontario Power Generation Inc. ("OPGI") is the owner of various properties within the Province of Ontario, on which are located Hydro One Transmission's facilities. OPGI and Hydro One Networks entered into lease and easement agreements with respect to these properties, effective April 1, 1999. Under subsection 5.01 of the easements and subsection 8(b) of the lease agreements, Hydro One Transmission is required to pay realty taxes with respect to its occupancy, to OPGI.

2.2 Transmission Lines

Hydro One Transmission's line corridors are assessed, and municipal taxes are calculated at a rate per acre of owned corridor land. These rates were established by Ontario Regulation 495/98 made under the Municipal Act and Ontario Regulation 494/98 made under the Education Act, titled Tax Matter – Taxation of Certain Railway, Power Utility Lands. As payments are made based on an area of land multiplied by a legislated rate, appeals must be based on corrections to the area of the property, or on the decision to reclassify a property as outside the utility corridor tax class.

An additional amount is paid annually to various First Nations bands for Payment in Lieu of Taxes ("PILs"), covering transmission lines and transmission stations on reserves. Since June 1988, Section 83 of the Indian Act has provided for taxation by First Nations, of property interests on their Reserve lands. Hydro One Transmission makes payments in lieu of taxes similar to taxes paid to municipalities that have Hydro One Transmission facilities contained within them.

2.3 Other

Other municipal property tax costs relate to costs on other sundry properties, such as transmission communication towers, and administrative buildings.

3.0 INDEMNITY PAYMENT TO PROVINCE

The Ontario Electricity Financial Corporation (OEFC) has indemnified Hydro One Transmission with respect to the failure of the transfer orders (orders used to establish the company as one of the successor companies to the former Ontario Hydro) in 1999.
The OEFC indemnification covers any defects in the transfer orders encompassing the following areas:

- the transfer of any asset, right, thing, or any interest related to the business;
- some adverse claims or interests of third parties or based on property title deficiencies arising from the transfer orders, except for some claims and rights of the Crown; and,
- claims related to any equity account previously referred to in the financial statements of Ontario Hydro including amounts relating to any judgement, settlement or payment in connection with litigation initiated by certain utilities commissions.

The Province has unconditionally and irrevocably guaranteed to Hydro One Transmission the payment of all amounts owing by the OEFC under its indemnity. Hydro One Networks pays an annual fee of $5.0 million to the OEFC. As the transfer order relates primarily to land assets, the amount allocated to Hydro One Transmission is based on the proportion of Hydro One Transmission land assets in relation to the total land assets of Hydro One. This results in $4.5 million of the $5.0 million total being allocated to Hydro One Transmission.

4.0 RIGHTS PAYMENT

Through agreements or permits, Hydro One Transmission line facilities cross and/or occupy properties owned by railway companies (e.g. Canadian National) and/or governmental bodies (e.g. Federal Government, Rideau Canal). According to the terms of the individual agreements, Hydro One Transmission pays an annual fee to the railway companies and the government entities for the right to cross and/or occupy their properties. These agreements contain rental review provisions allowing for rent increases tied to increased land values, subject to negotiation by both parties. The Company anticipates increased costs as reviews within the individual agreements are triggered, due to recent increases in land values. Rights payments associated with the railway companies are currently under review and steps are being taken to reach new agreements.

At this point Hydro One is not able to predict the outcome nor the timing of the future negotiated agreements and the amount that it will have to pay to secure the crossing or occupation rights with railway companies. However, for planning purposes, the rights payments for the 2011 and 2012 test years are budgeted to be $3.0 million per year.

Through agreements or permits granted by the Department of Indian and Northern Affairs, Canada ("INAC"), Hydro One has approval for its transmission and distribution facilities (that is, lines and transformer and distribution stations), to cross and/or occupy

First Nation Reserves. Some of these permits and agreements require Hydro One to pay annual rental fees, the payments of which, are administered by INAC.

The transfer orders by which Hydro One acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999 did not transfer title to some assets located on lands held for First Nations under the Indian Act (Canada). The transfer of title to these assets did not occur because authorizations originally granted by the federal Minister of Indian and Northern Affairs for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant First Nations or, in several cases, because the authorizations had either expired or had never been properly issued. The transmission portion comprises approximately about 82 kilometres of transmission lines, primarily, held by the OEFC. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of them to the Company. Hydro One is seeking to obtain from the relevant First Nations, the consents necessary to complete the transfer of title to these assets.

Hydro One cannot predict with accuracy the aggregate amount that it may have to pay to obtain the required consents; for planning purposes, however, the First Nations rights payments for the 2011 and 2012 test years are budgeted to be $1.5 million per year. This amount is based on continuing payments and the current status of the on-going negotiations with various First Nations bands.

CORPORATE STAFFING

1.0 OVERVIEW

Hydro One faces the prospect of unprecedented challenges in the years ahead associated with the availability of skilled and professional staff to operate, sustain and develop its transmission and distribution systems. This issue is not unique to Hydro One, but applies to the Canadian electricity sector as a whole. In its 2008 study of the Canadian electricity industry (*Powering Up the Future, 2008 Labour Market Information Study – Full Report*, available at www.brightfutures.ca), the Electricity Sector Council states, "The Canadian electricity sector is about to enter into the eye of the perfect storm, whereby the supply of trained workers is decreasing just at the same time that a significant proportion of the current workforce is retiring, and the demand for electricity and investment in new capital and infrastructure projects is increasing". The study further states "The line of business that will be most affected by the retirements is transmission, which will see an increase in retirements of over 750% by 2009 and over 900% by 2012. The sector as a whole is expecting to experience a doubling of retirements by 2009 and an increase of over 160% in retirements by 2012".

Hydro One's greatest corporate risk with respect to its human resources continues to be an aging workforce and, with a world-wide scarcity of core skills in the electricity industry, a highly competitive labour market. By December 31, 2009, approximately 1,000 Networks staff (transmission and distribution) were eligible for an undiscounted retirement. By December 31, 2012, approximately 1,600 Networks staff are eligible for an undiscounted retirement. Hydro One is seeing a larger uptake in actual retirements. In Q1 2009, 23 employees retired while in Q1 2010, 39 employees retired. This represents an increase of just under 70%. This is a trend which is expected to continue through the next decade and is consistent with challenges faced by other utilities in the electricity sector throughout the world. Recent studies suggest that up to half the workforce in the North American electricity industry will be eligible for retirement in the next five years[1]. Furthermore, it is anticipated that a greater number of staff eligible to retire will elect to retire sooner given the increased competition for these scarce resources in the marketplace.

Hydro One faces additional human resources challenges, recognizing the need to support the work associated with significant changes occurring in the Ontario electricity industry, including:

- The promulgation of the government's *Green Energy and Green Economy Act, 2009* in May 2009;
- The government's announcement with respect to the shut down of two coal-fired generating units at Lambton and two units at Nanticoke in 2010, in advance of the shut down of all coal-fired generating units by 2014;
- The indefinite delay in the in-service date of new nuclear generation, previously assumed to be 2018 in the IPSP;
- The September 21, 2009 direction letter from the Minister of Energy and Infrastructure to Hydro One to undertake a program of expansion and renewal of the transmission and distribution systems over the next three years and beyond, with the objective of maximizing opportunities to harvest renewable energy in the province.

Significant electricity transmission (and distribution) facilities will be needed to factor in these changes, including the electrical connection and delivery of electricity from more renewable and other sources of energy generation facilities.

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[1] Lester B Lave et al, The Aging Workforce: Electricity Industry Challenges and Solutions, Electricity Journal (2007), doi: 10.1016/j.tej.2006.12.007.

To meet these challenges, new skill-sets and disciplines, in addition to traditional ones, will be required. Many of the new staff that Hydro One will be acquiring will be new also to the transmission and distribution industry or to the workforce in general. These problems are further exacerbated by competing demands for the same and limited supply of electricity sector workers, both in Ontario, Canada or globally.

To address this demographic challenge, Hydro One has been proactive by implementing a number of initiatives. These include implementation of a staffing strategy as well as recruitment and training of new staff. These initiatives are discussed in the sections which follow.

2.0 STAFFING STRATEGY

Hydro One has an integrated workforce for its transmission and distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations. Examples would include a centralized control centre, one fleet operations, and an integrated asset management strategy.

Hydro One utilizes a work-based approach to staffing, whereby the Company resources according to work programs rather than plans the work around the number of internal resources available. To address the fluctuating and seasonal nature of work programs, the Company maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, temporary, hiring hall and contract staff.

Matching staff to dynamic work programs requires a rigorous approach to staff planning. The company must consider the amount of work to be done, the nature of the work and the skills required, as well as the most cost effective means of acquiring those skills, within the constraints of the collective agreements. Demographic and skills analyses are conducted annually to ensure that Hydro One retains the appropriate talent in the present and is positioned properly in the market to attract the talent we need in the future.

Progress has been made in attaining the optimal number and mix of staff required to complete the Company's increasing work programs. However, the increases in some of Hydro One's Transmission and Distribution programs will add additional challenges, given the tight competition for labour and power system professionals. It is essential because of the long learning curves required for competent performance of our highly skilled jobs that we hire well in advance of expected retirements.

3.0 RECRUITMENT

To help address the significant wave of retirements in its critical trades, technical and engineering groups, Hydro One continues to hire into its Apprentice and Graduate Training Programs. Since January 1, 2004, 280 graduate trainees have been hired through the Company's on-campus recruitment program. New Graduates bring not only much needed skills but also new perspectives and fresh energy to the work of Hydro One.

Hydro One also continues its recruitment into trades apprenticeship and technical training programs and has partnered with universities and colleges to develop curricula that educate students in areas where we face a shortage of skilled professionals and trades people. Hydro One has taken a leadership role in support for power system engineering programs, assisting in developing on-line power system engineering programs and providing scholarships to encourage enrolment in key areas where we face a labour shortage.

In addition, Hydro One, with the clear support of the PWU and the Society, has become a corporate participant in Career Bridge – a national, private-sector, non-profit initiative, which aims to provide internationally qualified professionals with Canadian work experience in their field of expertise.

Hydro One will also continue its support of the University and College Co-Op Education Program, hiring approximately 300 co-op students a year. This is a mutually beneficial process in that Hydro One gains bright, skilled workers trained in the latest theories and practices to work for four-month or eight-month work-terms, while the students gain "real world" work experience that can be used to develop their future careers. We have also found that the Co-op programs have proven a rich source of talented candidates for Graduate Trainee positions by offering us an opportunity to assess the student's "fit" and long-term potential with the company. Once hired our experience shows that these former co-op students have a shorter learning curve than other new hires with no previous Hydro One experience.

Hydro One has entered into a Fellowship Program with the Ryerson and McMaster Universities. This program, which commenced in 2008, provides high achieving students interested in the Electrical sector with summer employment opportunities. Chosen students will work 3 consecutive summers with Hydro One. They will attend mandatory weekly power system courses in addition to being exposed to real electrical sector work. Thirty students from each of McMaster and Ryerson started in this program in 2008. Upon successful completion of the 3 summer work terms, the students will receive a Hydro One Power Utility Certificate. Upon graduation, these students will be likely candidates for full time opportunities with Hydro One.

External recruitment into entry level new graduate or apprentice positions has been successful. Hydro One has had some difficulty attracting more experienced external candidates into higher rated technical, engineering and management positions. For these positions, factors such as compensation and head office location sometimes act as barriers to successful recruitment.

Hydro One believes a more sustainable and longer term strategy to deal with large scale retirements, is to invest in programs where knowledge transfer is the key objective. Programs such as new Grad and Apprentice Hiring, Fellowships and Knowledge documentation all contribute to ensuring knowledge is transferred to more junior staff.

4.0 TRAINING

To address the demographic issue, it is not enough to only hire new staff. Hydro One is active in developing current staff in order to enhance and/or develop new skills.

4.1 Trades and Technical Training

Hydro One provides a comprehensive selection of trades and technical training, designed to target the specific needs of field staff in relation to the work requirements of the asset base.

4.2 Leadership and Senior Management Development

The primary objective of this program is to ensure that Hydro One has a systematic management development framework. This helps ensure we retain a competitive advantage by developing, maintaining, and enhancing those management competencies deemed to be essential.

Hydro One has established a Management Development Steering Committee to oversee the identification of management development needs in the Company. The committee includes senior managers from both line and support functions, and is also responsible for the succession planning process.

4.3 Succession Planning

A Succession Planning Process has been developed for all senior management staff within the Company. The program's goal is to ensure that for each of the senior management positions, at least two successor candidates have been identified, and that a developmental plan for each of the candidates is developed and implemented.

4.4 Engagement

As discussed in Exhibit A, Tab 14, Schedule 1, Cost Efficiency/ Productivity, Hydro One has embarked upon a program committed to maintaining high levels of employee engagement. Employee engagement, which is a key differentiator in terms of business success, is the extent to which employees commit to someone or something in their organization. It can influence how hard they work and how long they stay as a result of that commitment. Engaged employees provide greater discretionary effort which often leads to increased productivity. Recent survey results show that Hydro One has made improvement in employee engagement.

5.0 HYDRO ONE'S LABOUR PROFILE

As part of Hydro One's strategy to efficiently and economically manage its fluctuating work requirements, Hydro One utilizes four broad groups of staff: regular employees, temporary employees, casual workers (the Building Trade Unions -BTU's under agreements with the Electrical Power Sector Construction Association – EPSCA, the Labourers' International Union of North America - LIUNA, the Canadian Union of Skilled Workers - CUSW, and Power Workers Union - PWU Hiring Hall employees) and contract staff, discussed below.

5.1 Regular Employees

Regular Employees of Hydro One can be placed in three categories:

i) PWU represented staff: The PWU is an industrial union that represents the trades, operators, technicians and clerical workers. They perform line work, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operation, technical and clerical/administrative work.
ii) Society represented staff: The Society is a professional union that represents engineers, technical, administrative and supervisory staff. They perform engineering, high level technical and administrative work as well as supervisory functions.
iii) Management staff, who are excluded from representation because they carry out managerial duties or work on confidential labour relations matters or legal matters.

5.2 Temporary Employees

Temporary employees are employees in any of the three categories set out above, engaged in work that is not of a continuing nature.

5.2 Casual Workers

Although the PWU does perform some construction work, the majority is performed by the PWU Hiring Hall, the Building Trades Unions (under agreements with EPSCA), the

Labourers, and members of the Canadian Union of Skilled Workers

i) Hiring Hall Employees (PWU) are utilized to meet fluctuating work demands, performing primarily supplemental construction and maintenance work on the distribution system. Non-recurring work peaks and special projects are resourced through the hiring hall.

ii) Fifteen construction BTU's supply a contingent workforce through their hiring halls, negotiating their collective agreements with EPSCA. These represent the construction trades employed by Hydro One, with the exception of those represented by the CUSW and the Labourers.

iii) The Labourers' International Union of North America is a construction union that Hydro One negotiates with directly as opposed to via EPSCA.

iv) The CUSW represents lines and electrical tradespersons who work on transmission construction, including the construction of lines over 50kV, transmission stations, switchyards, substations, system control centres, and associated telecommunications systems. Construction employees are contingent workers, accessed through the hiring halls to perform specific work programs and then laid off. They are paid a total wage package (including benefits and pension payments) for each hour worked. This relationship ensures that workers with the required skill set are hired in the right location for only the exact duration of the work assignment and that Hydro One has no on-going obligations with respect to benefits or pension for them.

5.4 Contract Staff

Contract Staff are individuals engaged as independent contractors, not on the Corporation's payroll. Contract staff are retained for their particular skill sets on projects, or to perform other work that is not of an ongoing nature. They are engaged at Hydro One for varying amounts of time and paid varying amounts commensurate with their skill sets and the market rate for that skill. Contract staff are tracked by work programs or activities and not by headcount. Where applicable, the procurement of contract staff is governed by the terms of the collective agreements between the Corporation and its respective unions where applicable.

6.0 SUMMARY

Attracting, motivating and retaining the right people is key to Hydro One's success. Despite the Company's efforts to date to ensure that we have an adequate supply of labour, it continues to face staffing challenges. In addition to the potential retirement of up to 1,600 employees in the next couple of years, there are increasing distribution and transmission work programs. Hydro One will continue to utilize a mix of regular, non-regular and contract staff in order to maintain the necessary flexibility to react to this increased workload.

In an industry with aging demographics and a highly competitive labour market, Hydro One needs to be positioned as an attractive employer if it is to succeed in recruiting and retaining staff with the requisite skills. To do so, it must provide challenging and rewarding job opportunities and a competitive compensation package. Hydro One believes its staffing strategy will allow us the flexibility to respond effectively and efficiently to any scenario that will arise over our business planning period.

COMPENSATION, WAGES, BENEFITS

1.0 INTRODUCTION

In earlier Distribution and Transmission decisions, the Board has expressed concerns regarding the levels of compensation at Hydro One. Hydro One understands these concerns and has strived, where possible, to reduce compensation related items. The fact remains, however, that Hydro One must maintain a highly skilled workforce, in the face of an aging workforce, world wide competition for similar skills, and an ever increasing work program.

In these unique circumstances, Hydro One believes that these compensation levels are reasonable. Ultimately, the rate payers benefit from the quality, expertise and reliability of Hydro One employees.

The overall compensation package at Hydro One is a product of historical factors as well as current and future challenges. Hydro One is heavily unionized and the work force is comprised of highly skilled and trained employees. In recent years, although work volumes have significantly increased, Hydro One has been able to minimize costs through greater management control of resources and the simplification of required job skills and associated pay levels.

With the de-merger of Ontario Hydro in 1999, Hydro One inherited collective agreements with firmly established terms and conditions of employment for represented employees. Since its formation, Hydro One has a history of managing collective bargaining in an effective manner by balancing the needs to reduce costs, increase productivity and settling collective agreements which the unions can support and ratify with its membership. Compensation at Hydro One is appropriate and reasonable given this history and context in which the Company operates.

2.0 THE UNIONIZED ENVIRONMENT

Approximately 90% of the work force is unionized. By law, Hydro One must negotiate collective agreements with each of its bargaining agents. The collective agreements establish the terms and conditions of the employment relationship for a fixed period of time. It is critical to understand that Hydro One inherited collective agreements from Ontario Hydro which established terms of employment. These legacy collective agreements established a 'floor' upon which future negotiations were based. While legacy collective agreements continue to strongly influence current Hydro One collective agreements, Hydro One has done much to change the status quo. Tables 1 and 2 demonstrate that Hydro One has been successful in reducing costs and/or increasing productivity through collective bargaining. This said, the ability of an employer in a unionized environment to reduce compensation is limited, particularly in a growing company which provides an essential service. In fact, recent experience in the auto industry illustrates how difficult it is to reduce compensation. Concession bargaining is normally only successful when the parties are faced with bankruptcy protection or plant closures. Hydro One has not bargained under these extreme conditions and so negotiating across the board wage reductions is unrealistic.

Collective Agreements are legal contracts. In labour agreements, more so than commercial contracts, parties must also consider their longer term relationship. Hydro One's Human Resources strategy is to negotiate fair and reasonable collective agreements to foster and promote healthy union – management relationships. In June of 2009, Hydro One was honoured with being named the top Corporate Citizen in Canada.[1]

[1] June 22, 2009 Globe and Mail *"The Canadian Magazine for Responsible Business"*

Ultimately, the rate payer is a beneficiary of this relationship in the form of higher productivity and, most importantly, uninterrupted supply of power.

3.0 LABOUR AGREEMENTS

Hydro One has collective agreements with the Power Workers' Union ("PWU"), The Society of Energy Professionals ("The Society"), the Canadian Union of Skilled Workers ("CUSW"), the Labourer's International Union of North America ("LIUNA") and each of the 15 Building Trade Unions ("BTU's") (via "EPSCA"). The key agreements are with the PWU and the Society.

The PWU represent over 70% of Hydro One employees. The PWU is an industrial union that represents the trades, operators, technicians and clerical workers. Its members perform line work, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operation, technical and clerical/administrative work

Society represented staff perform engineering, high level technical and administrative work as well as supervisory functions. The majority of the Society-represented employees in Hydro One have either post-secondary education (university degrees) and/or post-graduate education. These include graduate engineers, finance and telecommunication specialists.

4.0 COLLECTIVE BARGAINING

Progress has been made in reducing employee related costs and increasing flexibility.

4.1 PWU

An attempt by Hydro One to achieve significant cost reductions in wages, benefits and pension would likely result in a strike. The last PWU strike was in 1985 and lasted 12 days. It was handled by placing management and Society-represented staff in key functions to maintain operations/service to the extent possible. However, as a result of numerous downsizing programs, and reorganization of work, there are far fewer management staff available today with the requisite skills and experience to occupy key PWU positions during a strike. Furthermore, unlike other industries, Hydro One does not have a product that can be stockpiled. As a result, the Company would be unable to continue operations for a sustained period of time during a PWU strike.

Rather than risk jeopardizing the supply of reliable electricity, the company has sought to achieve overall cost reductions by negotiating increased management flexibility to run the operations, as opposed to wide scale reductions in wages, benefits and pensions.

4.2 Society

The Society was governed by mandatory mediation/arbitration since the formation of Hydro One until 2005. Mandatory arbitration is another legacy issue, that entrenched terms and conditions into Society collective agreements that were inherited by Hydro One. Interest arbitrators are generally reluctant to reduce existing wage levels. Similarly where a service is declared an essential service, thereby not having the ability to strike, collective bargaining disputes are resolved using mandatory interest arbitration. The C.D. Howe Institute has issued a study that examined the impact on wages when declaring a service an ‘essential service’.[1] This study concluded that an essential service

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[1] The C.D. Howe Institute. “No Free ride: The Cost of Essential Services Designation”, Benjamin Dachis 2008.

designation resulted in higher wage increases than would otherwise have occurred in traditional collective bargaining.

Hydro One ended mandatory arbitration commencing with the 2005 collective bargaining. In the first set of negotiations without this dispute resolution tool, the Society initiated a 15-week strike. The strike was primarily in response to Hydro One's desire to reduce wages and benefits and increase hours of work for new employees. Hydro One was requested by the Shareholder to enter into mediation – arbitration to end the strike. The resulting arbitration award did result in some cost savings for future hires, highlighted with less costly pension provisions for new Society employees.

5.0 OVERVIEW OF HYDRO ONE NEGOTIATIONS

The following tables highlight the significant changes achieved for PWU and Society negotiations since 2001.

Table 1
PWU Negotiations

Term	Changes
April 1, 2001 – March 31, 2002	• Modified Staff Reduction clause to allow for easier staff reduction. • Shortened the winter meal period by two months. • Summer student rates reduced to $12 per hour from rates as high as $19 per hour. • List of 14 province-wide automatic Purchase Service Agreements, whereas previously each PSA had to be individually negotiated, thus increasing efficiency and reducing costs. • New Hiring Hall classification of General Helper at $16.27 per hour. Previously, only regular staff, who are paid benefits and pension contributions, could be utilized for this work. • Renewed ability to have Lines staff on 2nd shift. • Agreement to allow Career Edge placements (develop skills for university /College students).

Term	Changes
April 1, 2002 – March 31, 2003	• New Temporary Work Headquarters process featuring travel allowances in place of Hydro vehicles, hotels and meals. • Generic Change of Employer clause to facilitate movement of employees from Hydro One to Inergi and future similar situations. • Retain temporary employees for 15 months (previously 12 months) and 18 months with Chief Steward agreement. • 50% of Training Instructors can be temporary instead of regular. • Made Linesperson second shift permanently available. • New lower cost Meter Reader B classification.
April 1, 2003 – March 31, 2005	• Ability to invoke streamlined staff reduction process. • Can rehire Meter Reader B at lower rate without a 6-month break in service. • PWU to provide Management with a list of Hiring Hall Meter Readers for direct call out to work by Management. This improves efficiency & reduces costs as Management can utilize available trained and experienced Hiring Hall Meter Readers. • Continue temporary work headquarters provisions. • CMS shift work provisions continued at mid-term agreement rates. • On-call established for Helicopter Pilots and Air Engineers. • Joint team to review health and dental costs with the goal of finding ways to reduce the total cost.
April 1, 2005-March 31, 2008	• Eliminated the PWU annual incentive plan that would have paid up to 6% of base pay per year with a savings of approximately $7.9 million per year in 2005. • Established a new three-day weekend shift in Lines. • Established a new lower-paid Switching agent classification and midnight shift. • Established full afternoon shift for Fleet Mechanics.
March 31, 2008-March 31, 2011	• Greater flexibility to employ University and College students. • Security clearances for new hires. • Pre hire assessment tool for apprentices. • Increased threshold for employees to qualify for post-retirement benefits. • Pensioners and surviving pensioners no longer able to add new dependents. • Cost Neutral on benefit changes and no pension improvements.

Table 2
Society Negotiations

Term	Changes
January 1, 2002-December 31, 2002	• Generic Change of Employer clause to facilitate movement of employees from Hydro One to Inergi and future similar situations. • Reduction in temporary travel expenses upon a paid move. • Reduction in sick leave benefit. • Reduction in benefits. • Greater flexibility to extend temporary employees.
January 1, 2003- March 31 2005	• Incentive Pay not renewed with a savings of approximately $2.9 million per year in 2003. • Interest Arbitration not extended. • Increase ability to use shift workers.
April 1, 2005 – March 31, 2008 (arbitrated settlement)	• New pension plan 25% less expensive. • Inclusion of a Management's Rights Clause. This affirmed Hydro One retains right to exercise discretion for issues not already negotiated.
April 1, 2008 –March 31, 2013 (early negotiations)	• Elimination of 1% Performance Pay with a savings of approximately $0.8 million per year in 2008. • Upper end of salary schedules reduced. • New lower hiring rates. • Jurisdiction, Dependent Contractor, Contracting Out grievances withdrawn. • Contracting Out language suspended to provide greater flexibility to contract out work • Security Clearances introduced

6.0 MCP COMPENSATION

Compensation for non-unionized employees (MCP) at Hydro One is reasonable. As discussed in Section 7.0 "Compensation Benchmarking Study", the 2008 Total Compensation Mercer Study concludes that Hydro One's MCP compensation is at median to its peer group. MCP employees do not receive across the board economic increases. Compensation adjustments are approved by the Board of Directors, as deemed necessary, to attract, motivate and retain competent staff. In 2009, Hydro One implemented the Ontario Government's request to restrict salary increases to 1.5% for all non-represented staff earning more than $150,000, and extended that restriction to all non-represented staff, regardless of salary level. In 2010, there will be no base pay adjustments made to MCP staff, with the exception of some MCP employees in Band 7 . Band 7 is the first management level beyond the jurisdiction of the Society and due to a wage compression issue with higher level Society and PWU positions, Hydro One determined it necessary to address this growing problem. Hydro One is aware that at least one successor company, OPG, has approved a 1.5% budget increase for non–unionized staff, including executives, in 2010

In 2004, Hydro One introduced a benefits and pension plan for new MCP employees that is approximately 25% less costly and increased the base hours of work for all MCP to 40 hours per week from 35 hours per week.

Hydro One has accepted the recommendations of the Arnett Panel regarding executive compensation. The basis of the Arnett Panel recommendations is an executive salary comparative benchmark of 15 public and 15 private sector companies. The executive positions at Hydro One will have their compensation altered as the incumbents leave in order to follow the guidelines recommended by the Arnett Panel. To date, the positions of Chief Executive Officer, General Counsel, and Chief Financial Officer have had their salaries reduced.

7.0 COMPENSATION STRATEGY

Hydro One has experienced rapidly increasing transmission and distribution work programs since 2004. Resourcing of these work programs must occur on the most cost effective basis possible within a highly competitive labour market.

Table 3 provides a snapshot of year end compensation costs for Hydro One Networks (Transmission and Distribution) from 2007 to 2012. The Company believes that the upward trend in these costs is reasonable in light of the steadily increasing transmission and distribution work programs since 2007, as well as the negotiated increases in labour rates.

Table 3
Year End Hydro One Networks Inc Payroll* (M$) (Tx and DX)

Hydro One Networks Inc. Payroll* (M$)					
Year	**Total Wages**	**Base**	**Overtime**	**Incentive**	**Other****
2007	495.5	414.7	60.9	6.6	13.2
2008	566.2	464.1	67.8	8.1	26.2
2009	623.2	504.5	68.2	9.2	41.3
2010	734.9	610.2	75.6	10.1	49.1
2011	794.9	651.7	79.6	10.2	53.2
2012	832.6	682.9	82.9	10.7	56.0

* This payroll reflects compensation costs associated with year-end headcounts for all EPSCA, PWU, Society and MCP Transmission and Distribution staff.
** "Other" includes travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination and a variable to address data restrictions.

Table 3 does not reflect the revenue requirement for compensation for this Application as it represents payroll costs for Hydro One Networks in total i.e. both Distribution and Transmission.

For the period 2010-2012, the total Networks (Transmission and Distribution) work program is expected to increase by approximately 6.6% and the regular plus non regular staff increase is expected to increase by approximately 6.3 %.

Hydro One believes that the goal of reducing overall wages, pension and benefits for future new hires reflects a reasonable balance between the need to attract and retain new staff while pursuing a more favourable cost structure. This is a difficult balance to achieve – too much of a reduction in compensation and benefits will impact the ability to attract the new skills necessary to replenish the workforce.

Hydro One's best performers are highly marketable, and a number of management staff have left the company in recent years. The Hydro One succession plan has facilitated internal promotion and a smooth transition in most cases, but our internal replacement capacity is now significantly diminished in key areas. External recruitment has proved challenging as our compensation levels and structures have fallen below the market for top people.

8.0 COMPENSATION BENCHMARKING STUDY

As directed by the Board in EB-2006-0501 Decision With Reasons, Hydro One engaged an independent party, Mercer/Oliver Wyman, to submit an independent, testable and repeatable report on compensation cost and productivity for Hydro One and comparable companies. This study, "Compensation Cost Benchmarking", was submitted in evidence in EB-2008-0272, Hydro One Transmission's cost of service application for 2009 and 2010 revenue requirement. As summarized in Table 4, the compensation benchmarking study found that the MCP and Society-represented staff were 1% below and 5% respectively above market median, or essentially at market median, whereas PWU represented staff were 21% above market median. As a result, Hydro One in total was said to be 17% above market median. However, the results of this study should only be applied with caution, for reasons set out below.

Table 4
Distribution and Transmission Compensation Benchmarking

			Below P50 Compensation			Above P50 Compensation	
Position	(#) of Hydro One Incumbents	Multiple of P50	0.5	0.75	P50 = 1	1.25	1.5
Non-Represented	151	0.99					
Represented Engineering	578	1.05					
Power Workers	1,966	1.21					
All	2,695	1.17					

Study results are essentially determined by PWU compensation levels. The Mercer Compensation study showed a few Hydro One classifications were above median, for instance, System Operator (26% above median), Regional Maintainer Lines (27% above median), Regional Maintainer Electrical (29% above median). Hydro One, where appropriate, is able to hire these similar classifications from the PWU Hiring Hall. Similarly, attention has been drawn to a few lower regular skilled positions which are also above market median. Again, Hydro One is able utilize the PWU hiring hall to complete accomplish work when these lower skills are required. As Hiring Hall resources do not receive Hydro One benefits or join the Hydro One Pension plan, these resources are less costly.

PWU wage rates at Hydro One are higher than wages paid at other Local Distribution Companies ("LDC's") for a variety of reasons and cannot be directly compared. Hydro One hires multi skilled employees to perform operations and maintenance work ie. Regional Maintainer – Lines, Mechanical or Electrical. These highly skilled classifications allow for a greater range of work to be performed by a single classification. LDC work is typically based-on dry land and not in the varied landscapes that exist at Hydro One. As a result, Hydro One staff are trained to operate a variety of off-road equipment and CVOR vehicles. Hydro One Regional Maintainer –Lines (RML's) employees are able to work on both Transmission and Distribution systems. These highly qualified staff can work on overhead, underground and submarine cables. RML's can perform specialized 'live line 'work where they are able to use live line tools to work on voltages ranging from 120 to 500,000 volts. By having highly qualified and flexible trades staff, Hydro One is able to service a very large geographic area efficiently and less costly since travel expenses are reduced and less staff are required to perform work.

In some cases, work performed at Hydro One is assigned to lower rated classifications than those at LDC's. Work performed by Hydro One technicians in Customer Operations is often performed by Engineers in LDC's. Work performed by higher graded PWU clerical staff can be compared to LDC's who typically employ higher rated Technicians.

9.0 2008 TRANSMISSION DECISION

In the EB-2008-0272 Decision with Reasons, the Board commented on the nature of collective agreements vis-a-vis normal commercial agreements. The Board held that collective agreements are differentiated from other goods and service contracts in that the parties to collective agreements do not have a similar arm's length relationship. As such,

> "(t)he Board's examination cannot include an analysis of the myriad of compromises and trade–offs associated with collective bargaining. The subjectivity related to that exercise would render it meaningless if not inoperable."

Hydro One asks that the Board consider the history of gains made through collective bargaining when assessing the prudency of the collective agreements. While it may be subjective, so too is a benchmarking study comparing Hydro One compensation levels to other utilities with different histories and facing different challenges and responsibilities.

10.0 COMPARISON OF COLLECTIVE AGREEMENTS

When assessing the prudency of Hydro One's collective agreements, a useful comparison would be the compensation wage scales for similar PWU and Society classifications in the Ontario Hydro successor companies as Hydro One competes for staff with these companies and is vulnerable to losing staff to these organizations. Such a comparison is instructive since all these wage scales have the same starting point, which is the establishment of the successor companies in 1999. It is important to compare compensation escalation based on total "dollar" base rates of similar classifications. Simply comparing accumulated base rate percentage increases does not capture the true difference between total base compensation paid at the successor companies.

In the two wage scale comparison tables for each of PWU and Society staff which follow the wage scale rates shown are for the top end of the wage scale band.

Power Workers' Union – Wage Scale Comparisons, 1999 and 2009

	1999	2009	Percent Change
Mechanical Maintainer/Regional Maintainer - Mechanical			
Hydro One	$ 28.23	$ 38.30	36%
OPG	$ 29.08	$ 44.72	54%
Bruce Power	$ 29.08	$ 50.73	74%
Shift Control Technician/Regional Maintainer - Electrical			
Hydro One	$ 28.23	$ 38.30	36%
OPG	$ 30.31	$ 44.72	48%
Bruce Power	$ 30.31	$ 50.88	68%
Clerical – Grade 56 (based on 35-hour work week)			
Hydro One	$ 21.46	$ 29.12	36%
OPG	$ 21.46	$ 28.56	33%
Bruce Power	$ 21.46	$ 31.62	47%
Clerical – Grade 58 (based on 35-hour work week)			
Hydro One	$ 24.20	$ 32.84	36%
OPG	$ 24.20	$ 34.79	44%
Bruce Power	$ 24.20	$ 35.65	47%
Regional Field Mechanic/Transport & Work Equipment Mechanic			
Hydro One	$ 26.20	$ 35.56	36%
OPG	$ 26.20	$ 44.72	71%
Bruce Power	$ 26.20	$ 42.58	63%
Stockkeeper			
Hydro One	$ 23.27	$ 33.15	42%
OPG	$ 23.27	$ 34.79	50%
Bruce Power *	$ 23.27	$ 39.87	71%
Labourer			
Hydro One	$ 19.03	$ 25.82	36%
OPG	$ 19.03	$ 34.79	83%
Bruce Power *	$ 19.03	$ 39.87	110%

**** Assumes that the position falls within the Civil Maintainer II classification and corresponding wage rate.***

For PWU staff, Hydro One has negotiated substantially lower wage scales than OPG and Bruce Power for all seven positions with the exception of one.

Society of Energy Professional – Wage Scale Comparisons 1999 and 2009

	1999	2009	Percent Change
MP2			
Hydro One	$ 77,954.79	$ 90,686.36	16%
OPG	$ 77,954.79	$ 92,026.10	18%
Bruce Power	$ 77,954.79	$ 90,666.01	16%
IESO	$ 77,954.79	$ 106,809.54	37%
MP4			
Hydro One	$ 88,651.39	$ 103,052.68	16%
OPG	$ 88,651.39	$ 104,593.53	18%
Bruce Power	$ 88,651.39	$ 103,080.86	16%
IESO	$ 88,651.39	$ 121,419.54	37%
MP6			
Hydro One	$ 100,756.80	$ 117,193.07	16%
OPG	$ 100,756.80	$ 118,923.51	18%
Bruce Power	$ 100,756.80	$ 117,215.50	16%
IESO	$ 100,756.80	$ 138,064.50	37%

For Society staff, Hydro One, OPG and Bruce Power have successfully negotiated lower end rates. The IESO has continued with the wage schedule structure that existed at demerger.

In addition to the comparison of base rate wage scales, the following two charts highlight significant additional incentives and allowances over and above the base rate wage scales for each of PWU and Society staff at other successor companies. These incentives are not reflected in the preceding wage scale comparison tables.

PWU– Additional Payments, 2009

	Incentive Pay
Hydro One	• No skilled based/competency payment.
OPG	• In 2002, OPG introduced Skill Broadening, which led to eligible employees receiving a $1,000 lump sum, as well as a wage increase of 5% (in addition to the general wage increase of 2% for that year).
Bruce Power	• In 2003, Bruce Power implemented a competency-based progression plan, which provided up to a 12% increase for journeypersons and a 6% increase for supervisors. • Bruce Power has also introduced Multi Trade rates for certain classifications, which are higher than the competency-based rates.

Society of Energy Professionals – Additional Payments, 2009

	Incentive Pay
Hydro One	• No incentive plan.
OPG	• Pays a number of bonuses for supervision, specialized work, training/certification and retention. • Tends to have more provident benefit plans than Hydro One. For example, paramedical care: OPG provides $1500 per year; Hydro One provides $500 per year based on 50% co-insurance.
Bruce Power	• Has a bonus plan for 2009, which if Company targets are met, pays 2% for MP2 and MP3, 4% for MP4 and MP5, 6% for MP6 (additional 1% available if stretch targets met). • Pays a number of bonuses for supervision, specialized work, training/certification and retention.
IESO	• Has a Performance Pay Plan where the Company will make a minimum performance payout of 1.5% of base payroll.

In an IESO OEB Decision (EB-2008-0340), the Board accepted the recommendations of the technical committee that the IESO compensation was reasonable. It is noteworthy that Hydro One's compensation for Society staff at both the lower and upper end of the wage scale bands are lower than that at the IESO. Further, in its Decision With Reasons in EB-2007-0905, the Board accepted OPG compensation levels. In both these Decisions over the past year, the OEB has accepted the compensation levels of entities that pay more for similar positions at Hydro One. In addition, it is quite clear that compared to these four other companies, Hydro One has been quite successful in controlling costs in collective bargaining over the past ten years to the benefit of all ratepayers.

Utility Industry Wage Increases

A cross section analysis of negotiated wage increases in the Canadian utility sector shows a 3.2 per cent per year[2] average wage increase between 1999 and 2009. The average increase for PWU employees is 3.35 percent and 3.00 percent for Society employees over the same period. Mercer has projected the average 2010 salary increase for all employee groups in the utility sector is 3.5%. The PWU and the Society have negotiated 3% economic increases for 2010. Hydro One has demonstrated since demerger in 1999, unionized rate increases has been consistent with increases negotiated throughout the utility sector.

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[2] January 13, 2010 Wage Tabulation from 1999 to 2010, prepared by Strategic Policy, Analysis, and Workplace Information Directorate. Employers included: ATCO Electric, ATCO Gas, B.C. Gas Utility Ltd., British Columbia Hydro and Power Authority, Bruce Power, Consumerfirst, Enbridge Gas Distribution, Enbridge Home Services, Division of Enbridge Services Inc., Enbridge Consumers Gas, Enmax Corporation, Epcor Utilities, Essential Home Services, Greater Vancouver Regional District, Hydro One Inc., Hydro-Quebec, Inergi L.P., Manitoba Hydro, Manitoba Hydro-Electric Board, New Brunswick Power Generation Corporation, Newfoundland and Labrador Hydro, Nova Scotia Power Incorporated, Ontario Power Generation, SaskEnergy Inc, Sask Power, Toronto Hydro, Terasen Gas Inc., TransAtla Utilities Corporation, Union Gas Limited,

11.0 SUMMARY

Compensation levels at Hydro One are reasonable and appropriate given the environment in which the Company operates. In recent years, despite significantly increased work volumes, overall costs have been minimized by the simplification of required job skills and pay levels where appropriate. Hydro One's demographic challenge requires us to be active in the labour market place and with world wide competition for these skills, there is a need for competitive compensation.

A strong barometer of Hydro One's ability to restrict compensation increases is a direct comparison to companies such as OPG, Bruce Power, and IESO. Hydro One competes directly with these organizations for skilled workers. Hydro One is also at risk of losing experienced staff to these organizations if our compensation is not competitive. Despite these competitive pressures, Hydro One has negotiated compensation levels that are less costly than OPG, Bruce Power and the IESO.

In addition, in a heavily unionized environment, there are significant constraints on an employer's ability to reduce compensation costs per employee. However, despite these constraints, the Corporation has made significant gains in the reduction of pension and benefits costs for MCP staff and pension costs for Society-represented staff.

As well, over time, as current employees retire and new staff are hired, lower Society wage schedules and the reduced compensation and benefit levels for new MCP hires should further reduce overall compensation costs. Compensation at Hydro One is heavily influenced from the legacy of being part of Ontario Hydro. However, Hydro One has demonstrated a track record of making progress on cost reduction and increased management flexibility.

PENSION COSTS

1.0 PENSION COSTS

Hydro One Networks is a participant in the Hydro One Pension Plan ("the Plan"). The Plan is a contributory, defined-benefit pension plan whose members comprise represented employees of the Power Workers Union ("PWU"), the Society of Energy Professionals ("Society"), MCP employees, pensioners who were employees, and pensioners who are beneficiaries of employees or pensioners.

The Board has previously allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). As well, in April 2006, the OEB in its Decision with Reasons, approved full recovery of Distribution pension costs included in OM&A (RP-2005-0020/EB-2005-0378). Pension costs were similarly approved for Transmission pension costs (EB-2006-0501 and EB-2008-0272); this treatment was continued in Hydro One Distribution's last cost of service application as well (EB-2009-0096).

Pursuant to the Inergi outsourcing agreement Hydro One Networks is also required to pay, directly to Inergi, a predetermined estimate of Inergi's annual current service pension cost in each year for each of the ten years of the outsourcing.

The Hydro One pension cost allocated to Hydro One Networks is based on the ratio of base pensionable earnings for Hydro One Networks' staff, as compared to the total base pensionable earnings for all of Hydro One employees. The method of allocation of the pension cost and the Inergi annual pension charge is consistent among all shared services costs, for operating and capital costs, and is consistent with the methodology reviewed during RP-2005-0020/EB-2005-0378, EB-2006-0501, EB-2007-0681 and EB-2008-0272, and continued in our current Hydro One Distribution cost of service application (EB-2009-0096) before the Board.

For the Transmission business, the annual charge to be recovered through rates is estimated as follows:

Annual cash pension cost (millions)

(*may not add due to rounding*)

	Transmission	Distribution	Other	Total
2011				
Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$ 29	$ 37	$ 3	$ 69
Capital	$ 18	$ 28	$ -	$ 46
	$ 47	**$ 65**	**$ 3**	**$ 114**
Inergi Annual Pension Charge				
OM&A	$ 1	$ 3	$ -	$ 5
2012				
Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$ 30	$ 38	$ 3	$ 71
Capital	$ 18	$ 29	$ -	$ 47
	$ 48	**$ 67**	**$ 3**	**$ 118**
Inergi Annual Pension Charge				
OM&A	$ 1	$ 1	$ -	$ 2

2.0 ACTUARIAL CALCULATION

The most recent actuarial valuation for the Hydro One Plan was as at December 31, 2006. In September 2007, Hydro One filed this actuarial valuation with the Financial Services Commission of Ontario (FSCO). The valuation showed that the Plan had a deficit of $216 million, on a going-concern basis. The required contribution for the Hydro One companies was initially set at $94 million starting in 2007 (actual contributions were about $95 million), variable based on the level of base pensionable earnings. Of this amount, about $70 million represented annual current service costs, and the remaining portion represented special payments over 15 years required toward the going-concern deficiency.

In accordance with applicable regulations, Hydro One makes all required contributions on a monthly basis.

Hydro One's next actuarial valuation will be prepared as at December 31, 2009 and will be filed with FSCO in September 2010. The valuation will depend on investment returns, changes in benefits, and actuarial assumptions.

The staff growth reflected in the increase in current service cost supports the requirements of the work program.

During 2008 and 2009, actual contributions were about $101 million and $112 million, respectively. Actual contribution requirements in 2011 and 2012 may differ depending on the level of base pension earnings used to compute the monthly contribution. As well, actual contribution requirements in 2011 and 2012 may materially differ from the estimates provided depending on the results of the next actuarial funding valuation as at December 31, 2009 which will be filed with FSCO in September 2010. The difference between the estimated and actual pension costs will be tracked in a variance account (see Exhibit F1, Tab 1, Schedule 2).

3.0 PENSION PLAN GOVERNANCE AND PERFORMANCE

Hydro One is the Plan sponsor and administers the pension assets and obligations of the Plan. As of December 31, 2009, the Plan had a reported net asset value of $4,336 million and about 12,549 members. About 40% of the Plan's members are active. The remaining Plan members are inactive, either retired, beneficiaries of retirees, former employees eligible for a deferred pension or members on long-term disability. The Plan governance was reviewed during RP-2005-0020/EB-2005-0378.

The Fund has consistently outperformed the benchmark made up of passive market indices. In the period from June 29, 2001 (the Fund's inception) to December 31, 2009, the Fund returned 5.13% annualized and the Fund outperformed its target benchmark return by 0.17%.

The Fund has a 61st percentile rank since inception (the 1st percentile is the top performing fund in Canada).

COSTING OF WORK

1.0 OVERVIEW

Hydro One Transmission's work program is bundled into packages of work identified as programs or projects. Program and project costs are comprised primarily of activities associated with labour, equipment and material acquisition. This Exhibit details the breakdown of each of these three cost activities, and how the costs are applied to programs and projects. This costing approach is consistent with the requirements of Canadian Generally Accepted Accounting Principles ("CGAAP").

Hydro One Transmission categorizes its costs into two major classifications - common and direct. Common costs, both OM&A and capital expenditures, are allocated to Transmission and Hydro One's other lines of business. Direct costs charged to work orders include labour (comprising salaries, benefits and pension costs), material, fleet and supply chain. Labour costs are calculated as a product of actual time multiplied by the standard labour rate. Material costs are charged directly to the work program. Fleet costs are charged using a fleet rate, and supply chain costs are charged via a material surcharge. All of these elements are described in detail in this Exhibit.

2.0 PROJECT AND PROGRAM MAJOR COST CATEGORIES

2.1 Labour Rate

Trade labour and equipment hours are distributed directly to benefiting programs and projects by using timesheets, consistent with common industry practice. Standard hourly labour and equipment rates are then used to convert the reported hours into costs. Both labour and equipment rates are "fully loaded" to ensure that all associated support costs required to deploy resources and equipment are accurately and cost effectively distributed to the benefiting work.

On an annual basis, the standard labour rates are derived based on information gathered through the annual budgeting process. Resource budgets for each major resource category are calculated and categorized into three basic cost components: forecast billable (direct charged) hours, forecast non-billable hours and forecast non-billable expenses. Total payroll and expense costs along with an assignment of support activity costs, divided by the forecast billable hours, create the standard labour rate. Table 1, below, shows an example of the composition of standard labour rate for one category, the Regional Electrical Maintainer – Regular Staff, over the period 2007 to 2012.

Table 1
Standard Labour Rate Composition
Regional Maintainer – Electrical
($ per Hour)

	Historic			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Payroll Obligations	72.58	72.88	68.88	71.46	73.62	75.93
Contractual time away from work	8.23	8.52	8.72	9.45	9.73	10.02
Time not directly benefiting a specific Program or Project	4.99	5.27	5.64	5.70	5.87	6.05
Field Supervision and Technical Support	11.85	17.11	19.54	16.08	17.31	17.34
Support Activities	9.35	14.22	15.22	16.31	16.47	16.66
Labour Rate	**107.00**	**118.00**	**118.00**	**119.00**	**123.00**	**126.00**

The cost elements embedded in the standard rate as illustrated in Table 1 are explained in the pages following, using the example of the position, Regional Maintainer – Electrical for the 2010 cost composition.

2.1.1 Payroll Obligations ($71.46)

A brief description of the cost elements included in this category is provided below. Compensation, wages and benefits are more fully explained in Exhibit C1, Tab 3, Schedule 2.

Base Labour and Payroll Allowances (58% of Payroll Obligations)

- Base Pay: Contractually negotiated and reflected in wage schedules.
- Payroll Allowances: Allowances are also contractually negotiated and stated in collective agreements. Regular staff (PWU) are entitled to travel, footwear and on-call allowances. Casual trades are entitled to board and travel allowances where circumstances require it.

Company Benefits (37% of Payroll Obligations)

- Regular Staff: Comprising pension (26.5% of base pensionable earnings) and current and post employment benefits; health, dental, etc. (25.9% of base pensionable earnings).
- Non-Regular Staff (for example, casual trades): Pension and welfare contributions made on behalf of the regular employee. These contributions are significantly lower in comparison to the Company benefit contributions made on behalf of the regular employee.

Government Obligations (5% of Payroll Obligations)

- Consists of Canada Pension Plan (CPP), Employment Insurance (EI), Employee Health Tax (EHT) and Workplace Safety and Insurance Board (WSIB) contributions.

2.1.2. Contractual Time Away from Work ($9.45)

This category consists primarily of employee vacation and statutory holidays, all established and identified in the Company's collective agreements. Sickness and accident costs are also included and are based on historical trends and consider current Company initiatives.

2.1.3. Time Not Directly Benefiting a Specific Program or Project ($5.70)

This category includes time for attendance of safety meetings, housekeeping and downtime often created due to inclement weather. These estimates are based primarily on historical trends.

2.1.4 Field Supervision and Technical Support ($16.08)

This category includes the costs associated with field trades supervision and other management and technical staff providing support services to manage and monitor the status of the assigned programs and projects.

2.1.5. Support Activities ($16.31)

Administrative Expenses and Centralized Support (66% of Support Activities)

- These costs include administrative expenses such as travel costs, cell-phones and other miscellaneous expenses that cannot be specifically attributed to a particular program or project. Also included is an assignment of costs for centralized clerical support activities and other centralized support to maintain mobile radios and facilitate work management system requirements.

Work Methods & Training (20% of Support Activities)

- Costs to design, develop and deliver work methods and training programs. Costs are assigned based on the forecast consumption of these services as agreed to by the Work Methods & Training function and service recipient.

Safety & Environmental Support (14% of Support Activities)

- Costs to design, develop and deliver safety and environmental practices primarily for staff working in field locations. Costs are assigned based on the forecast consumption of these services as agreed to by the Safety & Environment function and the service recipient.

2.2 Fleet Rate

Hydro One controls and manages approximately 5,700 vehicles and other fleet equipment to support its work programs used for both Transmission and Distribution work. Fleet Management is described in Section 3.0 of this Exhibit.

Fleet assets are categorized into 65 classes of equipment. For each equipment class, a standard equipment rate is calculated by dividing the annual forecast cost to maintain each class of equipment by the annual forecast hours that the class of equipment is required to work (utilization hours). Utilization hours are derived based on a review of historical trends and an annual review of the upcoming work program. Utilization hours are defined as the hours the equipment is being used "on the job". Table 2 below, shows the hourly fleet rate, as an example, for one of the commonly used classes of equipment in the Transmission business (a line maintenance truck) for historical, bridge and test years, illustrating that the rate includes all costs attributable to the benefiting work.

Table 2
Fleet Rate – Line Maintenance Truck
($ per Hour)

	Historic			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Operations & Repairs	$34.19	37.05	25.26	34.36	36.10	37.11
Fuel Costs	$5.84	6.01	6.52	7.85	8.08	8.32
Depreciation	$19.97	19.94	18.22	17.70	19.32	18.07
Hourly Rate	**$60.00**	**63.00**	**50.00**	**60.00**	**63.50**	**63.50**

Although the hourly amount for each variable comprising the fleet rate will fluctuate over time, the overall rate for a line maintenance truck remains quite stable. For example, fuel costs in total have increased and further increases are expected. The remaining two components: depreciation, operations and repair costs in general, illustrates an inverse relationship. With the purchase of newer vehicles, depreciation charges are relatively higher, whereas operations and repair costs are relatively lowered. The decrease in the 2009 rate is due to the realization of lower operations and repairs costs, as well as the volume of new vehicles acquired over the last 3 years in this class.

This savings is derived mainly from the decrease in the cost of repairs and inspections of equipment less than 3 years old. This savings, however, dissipates quickly and is illustrated in 2010 through to 2012, as we plan for increases in operations and repairs costs for the fleet. This strategy is also evident in our depreciation trend in 2009 and 2010, but does begin to increase again in 2011 as we purchase new equipment on our replacement cycle.

Below is a brief description of each category, with percentages reflective of the 2010 fleet rate.

Operations & Repair Costs (57% of Fleet Rate)

- This cost category consists primarily of repair costs (labour and parts) which are derived based on a forecast of the annual maintenance schedules for each piece of equipment. The age and the history of the vehicles are considered in the calculation. Throughout the year, all repair costs are charged directly to individual pieces of equipment. Operations cost include administration staff and their allocated share of central service support costs (for example, work methods and safety training activities).

Fuel Cost (13% of Fleet Rate)

- Fuel consumption cost is calculated based on past history (including distance driven), future fuel price projections and the composition of the class. Fuel consumption rate remains relatively stable between 2007 to 2009. This has resulted from the recent acquisitions of newer vehicles and equipment over the period with improved fuel efficiency, as well as our environmental initiatives e.g. reduced idling.

Depreciation (30% of Fleet Rate)

- The depreciation for each class is calculated based on Hydro One's current depreciation policies, the current composition of other fleet and the annual forecast additions and deletions.

External Fleet Rentals

Due to the seasonal and fluctuating nature of the work program, Hydro One Transmission requires externally owned equipment to meet work program peaks. Similar to the process used to cost its own fleet, Hydro One Transmission calculates and uses standard rates to distribute these costs to programs and projects.

2.3 Material Surcharge Rate

A standard material surcharge rate, which captures supply chain procurement costs benefiting a particular program or project, is applied to material costs. (A detailed description of Hydro One's approach to supply chain management is found in Section 4.0 of this Exhibit.)

Material costs charged to a project or program is based on the issue cost from Inventory, which is the Average Unit Price (AUP) or the direct-shipped purchase order price. On a monthly basis, total monthly material charges are surcharged with a fixed percentage cost to recover costs associated with purchasing, transportation and inventory management. The percentages range from 7% to 14%, depending on work program service requirements. The percentages are derived by assigning the costs of these activities to the work programs based on an annual assessment of the consumption of these services divided by the annual forecast of purchased material.

The costs recovered in the surcharge are as follows:

- Hydro One Costs: Management, demand planning, warehousing and transportation of material (comprising approximately 55% of the total costs).
- Inergi Contract Costs: Procurement and investment recovery (comprising approximately 45% of the total costs).

2.4 Other Program and Project Costs

Depending on the nature of the work, Hydro One Transmission's program or project costs also include additional costs beyond the major contributors identified above. These additional costs may include the costs of external contractors and/or miscellaneous job specific consumables such as travel expenses or the purchase of low value material.

In terms of estimating and costing of capital work, there may be circumstances when removal costs or customer contributions need to be separately identified. In these cases, the cost of removal work is accounted for as depreciation, and customer contributions are netted against gross capital costs.

Capital work also receives a monthly charge for its share of corporate interest and overhead costs. The composition of these two cost categories and the annual calculation are explained in Exhibit D1, Tab 4, Schedule 1, Allowances for Funds Used During Construction and Exhibit C1, Tab 5, Schedule 2, Overhead Capitalization.

2.5 Standard Rates

When using standard rates, residual costs naturally arise when actual costs incurred differ from the standards. These variances are accounted for on a monthly basis and assigned to both capital and maintenance programs. The monthly assignments of residual costs are made to OM&A and Capital based on the program and project cost activities responsible for generating the year-to-date variances.

3.0 FLEET MANAGEMENT SERVICES

Fleet Management Services provides centralized and turnkey services that include maintenance, administration, vehicle replacement and disposal. Vehicles are maintained to an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations, including, but not limited to, CSA225, the Highway Traffic Act and the Commercial Vehicle Operator's Registration regulations. Fleet Management Services also ensures that environmental impacts are minimized, and line-of-business productivity is optimized by minimizing downtime, and travel time, and by optimizing technology and continuous improvement opportunities.

Fleet Management Services has adapted to the changing needs of its business by:

- Revising the Company's model for responding to internal customers from fixed zone service to a mobile and fire hall model, with maintenance garages strategically placed throughout the Province to facilitate a more rapid turnaround for vehicle servicing;
- Rationalizing the Company's fleet and facilities (that is, optimizing the number of garages and geographical locations served);
- Reducing equipment downtime and improving our equipment utilization;
- Providing more competitive and cost efficient fleet support;
- Adopting a flexible service delivery model that matches the nomadic and variable work program needs of Hydro One's lines of business with service delivery options that mirror private sector practices. Such options include shift work, extended hours of service and mobile service delivery;
- Developing more timely, strategic and cost-efficient processes for equipment procurement and disposal;
- Developing a long-range capital replacement program; and
- Adopting data collection and information management systems that match the nomadic requirements of the Company's business units.

3.1 Maintenance Model

Fleet Management Services has developed a balanced maintenance model for mobile service delivery and centralized facilities. This model provides for 37 provincial locations and balances geographical customer requirements, travel time, third party vendor support and response time. Mobile/satellite repair units minimize costs by providing timely on-site field support for various nomadic work programs, such as vegetation control, new construction and off-road tower maintenance. Services provided to the lines of business meet the rigorous requirements of Fleet Management Services' agreements and are structured as a mobile and fire hall operating model to meet customer requirements.

3.2 Managed Systems

Fleet Management System

The strategic alliance to implement a fleet management system ("FMS"), developed with Automotive Resources International ("ARI") in 2003, was renewed in 2008. The implementation of the FMS created an automated web-based system that uses a single credit card for each vehicle to capture all operating costs including fuel, parts and repairs. The FMS also incorporates programs to manage contracts, such as tender agreements, and the system prescribes spending guidelines and negotiated discounts. The system measures a variety of targets that reconcile approved purchase orders, estimates versus actuals, and vendor-related expenditures, discounts and complaints.

The benefits of the FMS include:

- Improved scheduling of preventative maintenance, reduced repair times, travel time and reduced equipment downtime;
- Increased access to a number of vendors for fuel, repairs and parts, thus minimizing cost and downtime;
- Improved cost and efficiency, through carefully-considered procurement strategies and economies of scale, including improved volume discounts for fuel, parts and service;
- A 1-800 number for repairs, roadside assistance and towing and improved reporting and data collection.

The FMS uses a variety of linked programs to manage the data and information for all facets of the business, including internal and external repairs. This system and associated programs are operated in partnership with ARI, and take advantage of internal and external intelligence and technology.

The maintenance program minimizes avoidable and expensive repairs and minimizes equipment downtime, which results in improved equipment utilization. Both internal and external service providers have access to the appropriate information through state-of-the-art automated management systems, allowing for quality decision-making at all levels of the maintenance program. Examples of the information provided include:

- Real time vehicle history;
- Warranty criteria and warranty recovery;
- A work and resources scheduling tool;
- A pending and overdue work information alert system;
- Product information, including vendor-specific information;

- Repair and safe practices manuals;
- Process and policy information;
- Invoice and cost-management details;
- Monthly and ad-hoc reports; and
- Work order management.

GPS / Telematics

In 2009, Hydro One Fleet Services entered into a pilot program with ARI to install GPS (Global Positioning System) into 500 TWE units as part of the Hydro One Environmental Plan. This initiative is intended to provide data in the categories listed below in order to better evaluate patterns and habits of drivers with real-time information:

- Reducing engine idle time
- Decreasing miles driven
- Minimizing speed acceleration
- Reducing emissions
- Providing acceptable data for Fuel Tax Credits
- Reducing fuel costs

3.3 Fleet Complement and Utilization

Fleet Management Services controls and manages approximately 5,700 vehicles and other equipment primarily for Transmission and Distribution work. Inventory levels are controlled and set by the Hydro One Transmission lines of business and Fleet Management Services within the guidelines set for staffing versus fleet ratio, type and volume of work programs, geographic locations and utilization targets. The increase in the fleet complement, therefore, is directly related to the increase in the Company's work on system infrastructure and corresponding staffing levels. Fleet Management Services maintains 37 facilities to support 19 forestry locations and two brushing crews, 1,005 distribution stations, 279 transmission stations, 53 Provincial lines distribution locations and five transmission locations.

As capital and OM&A investments have been increasing, the options to meet increased equipment demand include the purchase, lease or rental of additional equipment, or increased utilization of existing equipment. The optimum option is to increase utilization, which minimizes capital investment compared to the option of additional purchases. Simultaneously, it maximizes the advantage of owned core equipment versus the additional cost of external rentals, which is 30 percent higher than owned equipment rates. This assessment is based on an internal comparison of the actual costs of equipment rentals versus those of owned core equipment.

The benefits of improving utilization include:

- decreased long term capital requirements;
- improved ability to respond to fluctuations in work programs; and
- reduced rental costs, with a correspondingly lower impact on the Company's OM&A budget.

Equipment utilization averages have increased from approximately 65 percent in 2001 to approximately 80 percent in 2009. The 2009 average equipment rate is $26.43; this is established by averaging all the individual equipment rates.

3.4 Fleet Management Services Budget

Fleet Management Services' annual budget is developed and managed based on the all-in costs of operating the fleet and the following criteria:

- Historical and forecast fixed and variable costs including fuel, depreciation, maintenance and repair, labour/staffing, external rentals and corporate allocations.

- Historical cost and mechanical fitness evaluations.
- Work program forecasts provided by the lines of business.
- Estimates provided by internal and external providers.
- The requirements of the capital/vehicle replacement program.
- Projected escalators.

Table 3, below, provides total expenditures on the components comprising the fleet rate for historic, bridge and test years. These expenditures are distributed among each of the 65 classes of vehicles.

Table 3
Fleet Management Services Budget Expenditures
($ Million)

	Historic			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Operations & Repairs	49.0	53.0	55.3	58.7	60.2	61.8
Depreciation	28.0	31.0	32.7	35.8	38.8	36.5
Fuel	20.0	24.0	20.0	27.7	28.5	29.4
Subtotal	**97.0**	**108.0**	**108.0**	**122.2**	**127.5**	**127.7**
Rentals	9.0	6.0	6.0	6.5	6.5	6.5
Total	**106.0**	**114.0**	**114.0**	**128.7**	**134.0**	**134.2**

3.4.1 Operations and Repairs

This cost category primarily consists of repair costs (external and internal labour and parts), the budget for which is based on a forecast of the annual maintenance schedules for each piece of equipment. The age and the history of the vehicles are considered in the calculations. Throughout the year, all repair costs are charged directly to each piece of equipment. Operations costs include wages, an allocated share of facility and telecommunication costs, and work methods and safety training activities.

3.4.2 Depreciation

The depreciation for each class within the fleet is calculated based on the current depreciation policies in Hydro One, and considers the current composition of the fleet, and annual forecast additions and deletions. Lease costs associated with Fleet's operating leases are also included in this category.

3.4.3 Fuel Cost

Fuel cost per class of equipment is calculated based on past history and current market projections as well as the current composition of the class. Throughout the year, fuel costs are charged directly to the particular piece of equipment consuming the fuel.

3.4.4 External Fleet Rentals

Due to the seasonal and fluctuating nature of the Company's work program, Hydro One Transmission requires the use of externally-owned equipment to meet the peaks in its programs. Using a process similar to that used to cost Hydro One Transmission's own fleet, standard rates are calculated and costs are distributed to the Company's programs and projects.

4.0 SUPPLY CHAIN MANAGEMENT

Hydro One delivers end-to-end supply chain services for the Transmission, Distribution and Remotes businesses. The focus is on the right product with the right quality, at the right place, right time and at the right cost.

The proposed 2011 costs for Supply Chain Services are expected to be $35.2 million, with a slight increase to $35.3 million in 2012. These services include strategic sourcing (purchase) of materials and services, storage and distribution of materials; demand planning, inspection services, transportation, inventory management, and investment recovery of disposed assets.

Supply Chain Services costs are allocated to work programs and projects through the material surcharge rate.

This section describes the budgeted cost levels, followed by a description of the components of Supply Chain Management.

Table 4
Supply Chain
($ Million)

	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Total	28.0	29.3	37.6	35.7	35.2	35.3

The increase in supply chain costs between 2007 and 2009 reflects the increase in transaction volumes supporting the growth in Hydro One's work programs, as well as cost increases related to transportation and warehousing, factory and manufacturing inspections, demand planning and expediting requirements.

For the 2010 to 2012 period, supply chain management is expected to experience an average decrease in costs of 1% representing the impact of planned process efficiencies while, supporting increasing capital and OM&A work programs across the organization.

Hydro One Transmission’s supply chain is a non-core service which has been out-sourced to Inergi L.P. The components of supply chain management performed by Inergi include sourcing (purchase) of materials and services, transportation, contract management and inspection services.

This agreement was contracted for the same service levels at a declining price over the term of the contract. The increasing overall cost levels represent increased volumes to meet business needs in the areas of contract management, inventory management, sourcing and demand planning.

4.1 Supply Chain Policies and Procedures

Hydro One Transmission operates a fair and transparent procurement process that gives all companies equal opportunity to do business consistent with its Procurement Policy and Principles.

Tenders and proposals are evaluated based on predefined evaluation criteria by cross-functional teams. The outcome of the evaluation is the foundation for awarding procurement contracts.

4.2 Sourcing of Materials and Services

The sourcing of materials and services, primarily carried out within Inergi, includes the following:

- Demand Management and Procurement – Market intelligence with respect to commodities, processing purchase transactions and inspecting and expediting services to ensure delivery to contract commitments.
- Sourcing and Vendor Management – Services to support sourcing all commodities and services which include managing the size and composition of the vendor base, resolving issues, managing inventory levels and negotiating stocking arrangements.

Hydro One Transmission manages its procurement and supply base by using strategic sourcing in the acquisition of goods and services. Strategic sourcing is a disciplined business process for purchasing goods and services on a Company-wide basis using cross-functional teams to manage the supply base as a valued resource. The methodology's five-step process includes spending analysis, market analysis, development of a sourcing strategy, negotiation and award and contract management.

4.3 Inspection Services

Inergi LP is engaged to provide timely inspection services to assure that products are manufactured in accordance to specifications established by Hydro One Transmission, and tracks costs and schedules on a product and project basis. For example, Hydro One has undertaken a replacement program for a wide range of its transformers that are near their end-of-life, requiring inspection during their manufacturing and testing.

4.4 Storage and Distribution of Materials - Warehousing

Hydro One Transmission's central warehouse operation in Barrie is responsible for the storage and distribution of materials for the service centres and station locations. This warehouse services two primary customers, Customer Operations and Grid Operations. Ten stock-keepers are assigned to the central warehouse. Customer Operations utilizes 18 field stock-keepers to service 64 field service centres. Similarly, Grid Operations leverages 32 Planning and Scheduling Technicians (PST's) at 23 stations. The field stock-keepers and PST's are responsible for receiving shipments and for storing and ordering material. Deliveries to the service centres are contracted to a third party transportation carrier.

4.5 Transportation

Hydro One Transmission manages its inbound and outbound transportation of materials through contracts with third party companies. In 2007, Hydro One Transmission entered into such a contract for material flowing in and out of the central warehouse. The strategy is to actively manage the cost of such traffic and reduce transportation cost year over year.

4.6 Investment Recovery

The final step of the supply chain is the disposal and investment recovery of end-of-life assets. This recovery is typically in the range of $2.2 million to $6.7 million per year, and primarily involves vehicle and scrap metal sales. Hydro One Transmission continues to focus on extracting the maximum value possible from the sale of these assets.

A breakdown of the sale of assets is noted in Table 5.

Table 5
Breakdown of Sales of Assets through Investment Recovery Program
($ Million)

Type of Sale	Recovery 2007	Recovery 2008	Recovery 2009
Vehicle Sales	0.8	1.1	1.1
Scrap Metal	4.2	5.5	1.2
Tools	0.0	0.1	0
Total	**5.0**	**6.7**	**2.3**

4.7 Cost Savings from Strategic Sourcing

Through its strategic sourcing initiative, Hydro One Networks will extract savings in the purchase of major equipment, commodities and services such as power transformers, circuit breakers, wood poles, distribution transformers, wire and cable, and pole and line hardware. Strategic sourcing results vary from commodity to commodity or from one service to another.

The main benefits of sourcing strategies are described below:

- Active involvement of internal stakeholders to communicate their business needs for the products and services;
- Cost reduction by increased leverage of Company-wide expenditures – purchases are consolidated by commodity and/or service to ensure that the business receives maximum value. This eliminates the need to tender and purchase as requirements surface -- an added benefit of this approach;
- Reduced total life cycle cost for materials and services – when purchasing equipment, all aspects are identified to ensure that Hydro One Transmission acquires maximum value for the life cycle of the equipment. For example, specifications, maintenance requirements, installation services and warranty services are defined and reviewed to ensure that business needs will be met, and order and invoice processes, lead time and

inventory requirements, etc. are evaluated to determine where greater efficiencies may be realized;

- Improved security of supply through longer-term agreements. To maximize value, longer-term agreements are established with fixed prices, or formula pricing is considered to ensure that Hydro One Transmission achieves best value;
- Improved and/or consistent quality of material and services.

Strategic sourcing will continue to be a major focus, as the Company emphasizes cost control and security of supply during a volatile commodity market, while demand in the global utility sector increases.

4.8 Recent Productivity Improvements in Supply Chain Management

Hydro One Transmission is interested in continuous improvement, and supply chain management is one example. This section details some work in progress to provide effectiveness and efficiency gains.

Previously, procurement of material for projects usually occurred after the release of the project. The supply management process is evolving, however, to consider the broader work program over multiple years, and obtain quotes for materials required over multiple delivery dates. This approach assists vendors by allowing them to better plan their activities, and leads to lower costs and a stronger relationship between Hydro One Transmission and the vendor – which has additional benefits if difficulties arise in the supply of materials.

Hydro One Transmission has also developed “Global Outline Agreements” with vendors to establish a standing order or relationship for critical materials, such as cable and autotransformers. In addition, the Company involves some suppliers in its planning activities, and studies historical buying patterns to assist in planning purchases.

In 2009, warehousing implemented a cross docking initiative to ensure receipting is done in a timely and compliant fashion. In 2010, warehousing will be implementing a bar coding system to further improve its effectiveness.

Streamlining standards is another way in which Hydro One Transmission is improving the strategic sourcing process. For large power transformers, for example, the Company currently has approximately 150 standards, which are being reduced to about 14. In addition to simplifying procurement, this also increases both the likelihood that spares will be available for use, and the ease of maintaining a lower inventory.

COMMON CORPORATE COSTS,
COST ALLOCATION METHODOLOGY

Allocation of common costs to Hydro One's Transmission and Distribution businesses and to each Hydro One affiliate is based on clearly articulated shared services and an established cost allocation approach based on cost causality principles.

The Common Corporate Costs OM&A programs include the provision of Corporate Common Functions and Services ("CCF&S"), Asset Management, Information Management Services, and Operating programs to support the Hydro One Networks Distribution and Transmission business.

CCF&S include corporate management activities, finance, human resources, communications, legal, regulatory, security, internal audit and risk management, strategic planning. Asset Management programs include developing asset strategies, policies and standards; identifying, planning and prioritizing specific OM&A and Capital work on distribution and transmission systems and monitoring the execution of the annual work program and real estate facility services.

A description of the Common Corporate Costs has been provided at Exhibit C1, Tab 2, Schedule 7.

In 2009, the Company commissioned a study by Black and Veatch (B&V) to update the methodology to allocate common costs among the business entities using the common services that was used in Hydro One's 2010/2011 Distribution Rate filing EB-2009-0096. The methodology developed represents the industry's best practices, identifying appropriate cost drivers to reflect cost causality and benefits received.

In 2010, B&V conducted a further review of the common costs allocation methodology that is used in this current filing. The report on this study is provided as Attachment 1 to this exhibit.

The update of cost drivers used in EB-2009-0096 resulted in a net overall shift in total CF&S costs from Distribution ($2.7 million or 1.0%) to Transmission ($2.2 million or 0.8%) and Telecom ($0.5 million or 0.2%). Incorporating the results of the 2009 Asset Management time study resulted in a 0.2% shift from Transmission to Distribution while the update of all other cost drivers using current actual or budget information shifted costs from Distribution to Transmission and Telecom.

The update of time allocations resulted in a shift from Distribution ($1.4 million or 0.5%) to Transmission ($1.0 million or 0.4%), Brampton ($0.2 million or 0.1%) and Telecom ($0.1 million).

Hydro One accepted the results of the B&V study as providing a reasonable and equitable approach to the assignment of common costs among the business entities using the common services. This methodology was based on the R. J. Rudden Associates (Rudden) Study that the Board accepted in the Distribution rate decision RP-2005-0020/EB-2005-0378.

The following Tables 1 and 2 provide the allocation of 2011 and 2012 CCF&S costs, respectively, to all business units.

Table 1
Allocation of 2011 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.2	2.6	2.3	0.1	0.1	0.0	0.1
Finance	29.2	14.5	13.3	0.7	0.3	0.3	0.0
Human Resources	18.6	9.6	8.6	0.3	0.0	0.1	0.0
Corporate Communications & Services	12.4	6.0	6.3	0.0	0.0	0.1	0.0
General Counsel & Secretariat	9.2	4.8	3.8	0.1	0.2	0.2	0.1
Regulatory Affairs	20.7	11.3	9.3	0.0	0.0	0.1	0.0
Corporate Security	2.8	1.3	1.4	0.0	0.0	0.0	0.0
Internal Audit	3.0	1.9	0.8	0.0	0.1	0.1	0.0
Total CCF&S Costs	**101.0**	**52.1**	**45.8**	**1.2**	**0.7**	**1.0**	**0.2**

Table 2
Allocation of 2012 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.2	2.7	2.3	0.1	0.1	0.1	0.1
Finance	28.8	14.4	13.1	0.8	0.3	0.3	0.0
Human Resources	19.3	10.0	8.9	0.3	0.0	0.1	0.0
Corporate Communications & Services	16.6	10.3	6.2	0.0	0.0	0.1	0.0
General Counsel & Secretariat	8.6	4.5	3.5	0.1	0.2	0.2	0.1
Regulatory Affairs	22.6	13.2	9.4	0.0	0.0	0.1	0.0
Corporate Security	2.9	1.3	1.5	0.0	0.0	0.0	0.0
Internal Audit	3.1	1.9	0.9	0.0	0.1	0.1	0.0
Total CCF&S Costs	**107.2**	**58.3**	**45.8**	**1.2**	**0.7**	**1.0**	**0.2**

Report to

Hydro One Networks Inc.

Regarding

Review of Shared Services Costs Methodology – 2010

February 26, 2010

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EXHIBITS

A. Background

Black & Veatch Corporation ("B&V" or "we") is pleased to submit this Report on our Review of Shared Services Costs Methodology (Transmission) – 2010 ("2010 Review") to Hydro One Networks Inc. ("Hydro One").

In 2004, B&V was engaged by Hydro One to recommend a best practice methodology to distribute the costs of providing the corporate functions and services ("CF&S"), including costs under its outsourcing contract with Inergi LP, to Hydro One and its subsidiaries ("2005 Review"). B&V recommended, Hydro One adopted and the Ontario Energy Board ("OEB") accepted a methodology to distribute those costs, as described in our *Report on Common Corporate Costs Methodology Review* dated May 20, 2005 ("2005 Common Costs Report").

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V Review	Business Plan	B&V Report
2006 Review	2007-2011	*Report on Implementation of Common Corporate Costs Methodology* dated May 31, 2006 (2006 Common Costs Report)
2008 Review	2009-2013	*Report on Implementation of Common Corporate Costs Methodology* dated September 10, 2008 ("2008 Common Costs Report")
2009 Review	2010-2014	*Report on Shared Services Costs Methodology* dated June 29, 2009 ("2009 Common Costs Report")

The OEB-accepted methodology has been applied by Hydro One to its Updated Business Plan ("Updated BP 2010-2014") data for its 2011/2012 Transmission Rates filing. This Report describes the "2010 Review" B&V performed, at Hydro One's request, of Hydro One's application of the methodology to its Updated BP 2010-2014, and B&V's conclusion.

Consistent with standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., counts of workstations, counts of FTEs, budgeted amounts) subject only to overall reasonableness and actual contrary knowledge, but without independent confirmation.

All amounts in this Report are in Canadian dollars.

B. Hydro One Organization

Hydro One Inc. is wholly owned by the Province of Ontario. It operates primarily through wholly owned subsidiaries: Hydro One Networks Inc., which includes the Transmission business and the Distribution business; Hydro One Brampton Inc. ("Brampton"); Hydro One Remote Communities Inc. ("Remotes"); and Hydro One Telecom Inc. ("Telecom"). See Exhibit B- Business Units for further information on these businesses.

CF&S comprises the functions and services identified in Table 1; Exhibit A –Corporate Functions And Services further describes the functions and services.

Table 1. **FUNCTIONS AND ACTIVITIES IN CF&S**

• Hydro One Inc. Corporate Office	• Telecom Services
• Corporate Services	• Customer Support Operations
• Finance	• Settlements
• Corporate and Regulatory Affairs	• Finance and Accounting Services
• Network Executive	• Human Resources
• General Counsel	• Supply Management Services
• ETS- Applications Support and Infrastructure Support	

The Updated BP 2010-2014 includes 2011 costs aggregating approximately C$303.3 million and 2012 costs aggregating approximately C$324.9 million, incurred to provide the corporate functions and services. These functions and services are provided, and costs are incurred, for the benefit of the business units identified in Exhibit B- Business Units.

Approximately 43% of the CF&S costs are incurred under an outsourcing arrangement with Inergi LP ("Inergi"). In this Report, CF&S includes the portions of Inergi services identified in Updated BP 2010-2014 as sustainment.

C. B&V Methodology

The B&V methodology for allocating the costs of Hydro One's corporate functions and services was designed to address the following:

- Compliance with OEB precedent including Docket RP-2002-0133
- Compliance with relevant provisions of the Affiliate Relationships Code for Electricity Distributors and Transmitters ("Code")
- Cost incurrence- Are the costs needed to perform services required by the business units?

- Cost allocation- Were the costs appropriately allocated to the recipient business units?

- Cost / benefit- Did the benefit received equal or exceed the cost?

An overview of the B&V methodology follows:

- Identify the functions and services included in CF&S

- Identify activities that are performed in order to provide the CF&S

- Distribute the annual cost in Updated BP 2010-2014 to perform each function and service among the activities required to perform it, based on time and/or cost studies

- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when not

The direct assignment of costs to business units when possible, and the use of cost drivers to allocate costs when direct assignment is not possible, is consistent with OEB precedent. A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The use of cost drivers conforms to OEB precedent, including Docket RP-2002-0133. The different types of cost drivers are described in Exhibit C - Types Of Cost Drivers.

The guiding principle that the B&V methodology seeks to use in assigning cost drivers is cost causation, which means there is a causal relationship between the cost driver and the costs incurred in performing the activity. Where cost causation cannot be easily implemented or established, selecting cost drivers based on benefits received is a fair and consistent treatment. Other factors considered are practicality; stability; and materiality.

D. Scope of Work

For the 2009 Review (Distribution), our assignment was to review Hydro One's application of the OEB-accepted methodology to its Updated BP 2010-2014. In preparing the 2009 Review (Distribution), B&V performed the following tasks:

1. Reviewed Hydro One's model for allocating Shared Services Costs, to determine if it implements the OEB-approved methodology for the CF&S costs in Updated BP 2010-2014.

2. Identified and evaluated modifications to the CF&S Model

3. Reviewed the data input to the CF&S model including budget data, allocator values, time distributions and cost distributions

4. Reviewed distributions of labor, non-labor and Inergi costs among departmental activities

5. Reviewed assignment and allocation of activity costs among business units

6. Reviewed Asset Management time study conducted by Hydro One

7. Performed analytical evaluations and comparisons to prior studies

These tasks are discussed in our 2009 Common Costs Report.

For the 2010 Review, we reviewed the changes from the original BP 2010-2014 to the Updated BP 2010-2014.

B&V also reviewed the computation of Overhead Capitalization Rate using the OEB-approved methodology applied to the Updated BP 2010-2014, and reviewed the Common Assets allocation using the OEB-approved methodology applied to the Updated BP 2010-2014, and has prepared reports on our work.

E. Tasks Performed

In this Section we will discuss each of the steps performed in the Scope of Work, as listed in Section .

1. Reviewed CF&S Model

In this task, we reviewed the model that Hydro One has developed for allocating corporate Costs ("CF&S Model"), to determine if it implements the OEB-approved methodology for the CF&S costs in the Updated BP 2010-2014.

B&V first reviewed the CF&S Model in connection with our 2008 Review. Similar reviews were performed for the 2009 Review and this 2010 review, including a review of:

- The identification of the activities performed by each department,
- The methodology for distributing departmental costs among the activities performed by each department, including time studies and other direct assignments,
- The methodology for distributing the costs of each activity among the business units, and

- The computations made by the CF&S Model.

Based on our review, the CF&S Model properly implements the OEB-accepted methodology for distributing the costs of corporate functions and services in the Updated BP 2010-2014. The CF&S Model distributes departmental costs among activities, then distributes the cost of each activity based on direct assignment or the use of cost-based allocators. The use of direct assignments and the selection of cost drivers were consistent with the direct assignments and cost drivers selected by Hydro One for the 2008 Review.

2. Identified and evaluated modifications to CF&S Model

The purpose of this task was to identify and understand changes to the CF&S Model since B&V performed the 2008 Review and the 2009 Review. In each case our goal was to determine the reason for the change and to evaluate if the B&V cost-based methodology continued to be applied by Hydro One. Changes to the Model from the 2009 Review were made primarily:

- To reflect the Updated BP 2010-2014 costs
- To update the cost driver values
- To update the time distributions and cost distributions
- To reflect organizational changes, and
- To reflect additions to and deletions of departmental activities.

Based on our review, B&V found that all of the changes to the CF&S Model were consistent with the OEB-approved B&V cost allocation methodology and that the results continue to produce a cause-based allocation of costs.

3. Reviewed data input to CF&S Model

The purpose of this task was to review the data entered to the CF&S Model to determine that it is properly used in the CF&S Model and is reasonable. Our review of reasonableness was based on discussions with Hydro One personnel and comparison to the prior Reviews performed by B&V. The following items were reviewed:

- Budget data for each department, detailed as to labor, non-labor and Inergi. Significant changes were explained by new departments, transfers of departments and changes in activity levels.
- External allocator values. Total values, and the portions attributed to each business unit, were reasonably consistent over time.

- Time distributions- Activity percentages were compared to the information prepared by the departments.

B&V found the data entered to the CF&S Model were properly used and were reasonable.

4. Reviewed distributions of costs among departmental activities

The purpose of this task was to determine the reasonableness of the distributions of labor, non-labor and Inergi costs among the activities performed by each department.

- Labor costs for each department were distributed among the activities performed based on the distribution of time incurred by department employees. The Hydro One manager responsible for each CF&S unit determined the portion of annual time spent by the personnel under his or her supervision on each of the departmental activities, based on concurrent time records, interviews with personnel and informed judgment. The information provided by the managers was reviewed by Hydro One financial personnel. B&V reviewed the methodology used by the Hydro One managers and reviewed the time charged to the departmental activities. B&V found the time distributions to be reasonable based on the detailed descriptions of each department's responsibilities (Exhibit B- Business Units), discussions with the departmental managers and Hydro One financial personnel, and comparisons to the departmental time distributions in the 2008 Review and the 2009 Review.

- Non-labor costs include OEB invoices, rate hearing expenses, communications programs, insurance costs and claims, human resources programs, labor relations programs, IFRS and Bill 198 consultant costs, controllership activities (outsourced to Inergi), actuarial consultants and audit fee. B&V found the distribution of these costs to be reasonable based on their nature.

- The costs of the functions and services provided by Inergi were distributed among the activities based on information provided by Hydro One, and estimates and judgments made by Hydro One and B&V. The approach to distribute the total costs these for each of the CF&S provided by Inergi is described below in the 2009 Review.

5. Reviewed Assignment and Allocation of Activity Costs Among Business Units

The purpose of this task was to determine the reasonableness of the allocation of the cost of each activity among the business units. B&V reviewed each activity and the assignment or allocator used to distribute the cost of the activity to the business units. The use of direct assignment and the selection of allocators were reasonable and reflected cost causation and / or benefits received, as described in Section . In addition, for the continuing activities in each department (i.e., almost all of the activities identified), the use of direct assignments and the selection of allocators for the Updated BP 2010-2014 costs was the same as in the 2008 Review and the 2009 Review.

Table 2 summarizes the types of costs drivers used to assign the CF&S costs. These amounts include the Inergi charges.

Table 2. **DIRECT ASSIGNMENTS AND COST DRIVERS USED FOR 2011 CF&S COSTS**

TYPE	$ ASSIGNED ($ Millions)	% OF TOTAL
Direct Assignment	$91.8	32.2%
Physical	50.9	16.6%
Financial	110.2	35.4%
Internal	50.4	15.8%
Total CF&S Costs	$303.3	100.0%

6. Reviewed 2009 Asset Management Time Study

Hydro One determined the portion of Asset Management costs devoted to Transmission and Distribution, respectively, by performing a time study for these personnel for the five-week period ending April 5, 2009. In connection with the 2009 Review, Black & Veatch reviewed the time study, as well as the two prior Asset Management time studies. Based on our review the Asset Management Time Study provides an appropriate basis for allocating the costs of activities performed by Asset Management personnel.

7. Performed Analytical Evaluations and Comparisons

The purpose of this task was to compare the results of the distribution of the Updated BP 2010-2014 CF&S among the business units to the results in the 2008 Review and the 2009 Review, and to understand the differences. This included a review of the proportions of total cost and departmental cost distributed to each business unit and the total cost assigned to each business unit.

The portion of each department that was distributed to Transmission, Distribution and Other was compared for this review, and for the 2009 Review, 2008 Review, 2006 Review and 2005 Review. The proportions have been reasonably similar over time and differences are explained by changes in the allocation of time, changes in allocator values and changes in departmental functions and activities.

F. Conclusion

The results of Hydro One's distribution of the CF&S costs in its Updated BP 2010-2014 are presented in Table 3- - 2011 and 2012 CF&S Costs, Updated Business Plan 2010-14.

Based on our review, Black & Veatch believes that the results of Hydro One's application of the B&V shared cost allocation methodology to its Updated BP 2010-2014 data for the years 2011 and 2012, as shown in Table 3, reflects a cost-causation-based distribution of the costs of providing the CF&S and conforms to the OEB-accepted methodology.

Table 3. **2011 AND 2012 CF&S COSTS, UPDATED BUSINESS PLAN 2010-14**

Business Unit	2011 Budget		2012 Budget	
	$ Millions	% of Total	$ Millions	% of Total
Transmission	$ 113.3	37.4%	$ 126.9	39.1%
Distribution	148.2	48.8%	155.9	48.0%
Others	41.8	13.8%	42.1	12.9%
Total CF&S Costs	$ 303.3	100.0%	$ 324.9	100.0%

EXHIBIT A –CORPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DESCRIPTION**
Hydro One Inc. Corporate Office	
Board of Directors	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary
Chair	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary
President and CEO	Primary accountability is leadership of the staff of the Corporation to ensure that their culture and behaviours lead to achievement of its strategic objectives. Develops and updates strategy and establishes performance targets to assess progress towards the goals and objectives defined by the strategy.
Vice President	Oversee and support Law, Regulatory and Corporate Secretariat General Counsel functions.
Corporate Secretariat	Provides direction and analysis in areas of: 1) Board and Committee(s); 2) Support to Office of Chair and members of Board of Directors; 3) Code of Business Conduct; 4) Community Citizenship; 5) Freedom of Information and Privacy, 6) Corporate Archives, 7) Corporate Records, 8) Corporate Secretariat Support
CFO's Office	The CFO provides Hydro One and its subsidiaries with strategic review and approval with respect to all financial and investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting are also provided by the CFO to Hydro One Inc. and its subsidiaries as required.
Treasurer's Office	Treasurer's Office is responsible for Debt and equity issuance, Capital structure management and oversight of Finance- Treasury function.
Donations	Includes donations made to support injury prevention, corporate donations (e.g. Salvation Army), energy education, United Way support and local community causes.

EXHIBIT A –CORPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DESCRIPTION**
Corporate Services	
Human Resources	Provides advice, guidance and services to managers (and on their behalf, to employees) which support and optimize the acquisition and management of the workforce, and the treatment of pensioners. Provides consulting, leadership development and recruiting, diversity and resourcing programs, compensation and benefits and labour relations services.
Labour Relations	Provides full-scale service pertaining to bargaining, Ontario Labour Relations Board hearings, grievance and arbitration hearings, advice and guidance, plus training to all levels of Hydro One management. This involves interaction with 21 different unions and 24 collective agreements.
Corporate Security	Provide Security Services for Company Assets; Theft of Power Program (Recovery of stolen electricity)
Information Management & Information Technology	Enterprise IT Architecture, Governance of IT architecture, Business Analysis and Information Management, Project Management & Control, Large Project Management, Inergi & Telecom services management.
Information Assets	Manage key asset customer database; provide integrated systems support; support Cornerstone
Cornerstone Enablement	Manage enterprise business processes, data quality and architecture; coordinate, track and improve training curriculum; develop power user network; identify, develop, assess and implement solutions to improve Cornerstone assets
Corporate Services- SVP	Oversight of Corporate Services department.

EXHIBIT A –CORPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DESCRIPTION**
Finance	
Corporate Controller	Corporate Accounting & Reporting; Revenue Management; Financial Modeling & Analysis; Corporate Planning & Reporting, Accounting Policy; Internal Control; IFRS; Regulatory Finance; Inergi Finance; Bill 198; Corporate Compliance
Treasury	• Risk management including insurance purchasing • Insurance claims settlement • Financial risk management-foreign exchange, interest, credit • Cash & banking operations-cash forecasting, strategy & banking relationships, bank account management • Debt management-prospectus, debt issuance, borrowing, maintain relationship with shareholders • Funds management-deployment of short term funds and manage longer term funds • Investor Relations is responsible for: Relationship with shareholders, creditors, equity analysts & rating agencies • Support business activities; project management • Decision support
Taxation	Meet internal and external tax compliance requirements and reduce the overall corporate tax liability through tax planning for current and new businesses, acquisitions and dispositions, special projects, tax compliance (including income tax, GST, PST, and DRC returns for all entities), tax accounting, lobbying for legislative tax changes, and government tax audits.
Corporate and Regulatory Affairs	

EXHIBIT A –CORPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DESCRIPTION**
Corporate Communications and Services	Supports all communications initiatives, both external and internal. Interacts with most other Hydro One departments but has a special focus on working with Customer Service department. Provides support of major projects including coordination of development and partnership activities; coordination with external energy agencies (e.g. - OPA, IESO), Ministries in the Ontario Public Service and internal Hydro One resources. Also participates in pre-public consultations with municipalities and First Nations.
Outsourcing Services	Manages the overall business relationship between Hydro One and Inergi LP.
First Nations and Metis Relations	Provide First Nations and Métis consultation advice and support; Provide advice re First Nations and Métis HR strategies; Provide strategic advice to Remotes with respect to First Nations and Métis issues.
Regulatory Affairs	Coordinate filing of applications filings with OEB; Compliance with OEB orders; Design and implement regulatory policy; Manage relationship with OEB. Specific tasks include: Cost Allocation and Rate Design for regulated Transmission and Distribution, in particular, rate structures and rates for Transmission and Distribution Tariffs; Assist implementation of approved Transmission and Distribution rates; Support transmitters' representative on IESO Technical Panel; Provide load forecasts for all business units of Hydro One and for IESO; Manage MV Star to support wholesale and retail settlement; Provided strategic and analytical support to load research and CDM initiatives.
Regulatory Affairs- OEB Cost	Direct billed OEB costs for Transmission and Distribution businesses.
Regulatory Affairs- Rate Hearings	Costs of Rate Hearings before the OEB for Transmission and Distribution businesses.

EXHIBIT A –CORPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DESCRIPTION**
Real Estate	Manage and acquire rights of way and easements; Manage property taxes; Manage SLU revenue programs; Manage Employee Relocation Program
Supply Chain Services	Manage warehouses; Strategic Sourcing Initiative; Supply chain management; Transportation; Investment recovery
SVP	Oversight of Corporate and Regulatory Affairs.
Network Executive	
External Relations	Support customer strategy, rate strategy, distribution generation strategy; Develop working relationships with customers, regulators, shareholder, lenders; Labour relations; Corporate culture
Internal Audit & Risk Management	Provides assurance that internal controls continue to operate effectively, identification and recommendations for areas where controls can break down or need improvement to meet corporate objectives.
General Counsel	
Law	Provides legal advice to all business units, acting as an internal “law firm” for the Corporation on most aspects of law affecting it, and is also well acquainted with day- to-day requirements of the Corporation.
Telecom Services	
Telecom Services	Provides telecommunications infrastructure across the Province, including both voice and data. Links staff and business applications at Trinity, Richview TS, Markham and London Call Centers, Mill Creek data centre, 125 field offices (400 total sites including stations) and customers via Call Centres and Web sites.

EXHIBIT A –CORPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DESCRIPTION**
Inergi Functions	
Customer Support Operations	Inbound Call Handling; Bill Production; Collections; Data Services
Settlements	Provide settlement and reconciliation services for wholesale and retail markets.
Finance and Accounting Services	Accounts Payable Billing; Accounts Receivable (Non-energy related); Fixed Asset and Project Cost Accounting; General Accounting and Planning, Budgeting and Reporting
Human Resources	Payroll and related services
Supply Management Services	Demand Planning, Demand Management and Procurement, Sourcing, Vendor Management and Inventory Management, Process Development and Data Management, Negotiating and managing transportation contract with logistics providers, Asset Disposal
Inergi ETS	
Applications Support	Support IT applications: Customer Support Operations, Finance, Human Resources / Cornerstone, Passport / Cornerstone, Market Ready, Telecomm Services.
Infrastructure Support	Support the infrastructure including platforms, servers, printers, workstations, IT communications and Help Desk.

EXHIBIT B- BUSINESS UNITS	
BUSINESS UNIT	**DESCRIPTION**
Trans-mission	Owns and operates substantially all of Ontario's electricity transmission system.
Distribution	Owns and operates a distribution system which spans approximately 75% of Ontario and serves approximately 1.1 million customers.
Brampton	Owns, operates and manages electricity distribution systems and facilities in Brampton, Ontario.
Remotes	Owns, operates, maintains and constructs generation and distribution assets used to supply of electricity to remote communities in northern Ontario
Telecom	Sells high bandwidth telecommunication services to carriers, Internet service providers, and large public and private sector organizations.
Shareholder	Represents activities performed exclusively for the benefit of the sole shareholder of Hydro One Inc.
Note- The cost distribution methodology also identified the costs to include in the Materials Surcharge, which are included in materials costs and ultimately charged to business units.	

EXHIBIT C - TYPES OF COST DRIVERS		
TYPE	**DESCRIPTION**	**EXAMPLES**
External Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Number of customers, employees, phone calls or workstations; time studies; MWh or MW
Financial	Financial information from accounting or management reports, budgets or projections	Capital expenditures, Net utility plant, Oper Maint (expense), Total assets, Total capital, Total revenue
Blended	Weighted combinations of other drivers, used when one or more drives are applicable and none is clearly preferable; weights determined by judgment	Non-energy Rev_Assets Blend = 50% weight for Non-Energy Revenue and 50% weight for Assets
Driver *xBusiness Unit*	Any driver may be modified by excluding one or more business units to which the activity does not apply	Cost driver for payroll preparation activity is FTEs (Full-Time Employees), but Brampton business unit prepares its own payroll and does not use the shared service, therefore activity cost driver is called FTE xB (Full-Time Employees excluding Brampton)
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	Cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities

OVERHEAD CAPITALIZATION RATE

This evidence will discuss the methodology used to allocate Common Corporate Functions and Services ("CCF&S") and Asset Management costs to capital projects.

Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overheads supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year.

In its August 16, 2007, Decision on the Company's 2007 and 2008 Transmission rates (EB-2006-0501), the Board accepted the methodology, recommendations and the allocation of costs from a study by RJ Rudden Associates (Rudden). This study had been commissioned to derive an overhead capitalization rate for Hydro One Transmission's CCF&S and Asset Management costs. The accepted methodology was used in the prior Transmission rate filing EB-2008-0272 and Distribution rate filing EB-2009-0096, The methodology was also confirmed by Black & Veatch (B&V) formerly RJ Rudden Associates.

In 2010 the Company commissioned B&V to review and update the capital overhead methodology. The methodology was based on the previously accepted Rudden Study. The 2011-2012 overhead capitalization rates have been calculated consistent with the revised B&V study methodology. The consistency in the use of this approach for the 2011 and 2012 test years was reviewed by B&V in 2010, and is provided as Attachment 1 to this Exhibit.

Hydro One Networks in 2007 began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs. This results in a better alignment of overhead costs with the capital projects that they support and removes the need for an e-factor adjustment.

Hydro One proposes that the resulting overhead capitalization rate as calculated in the B&V study in 2010, continues to be a reasonable method of distributing CCF&S and Asset Management costs to capital projects. Hydro One's submissions in this Application reflect the overhead capitalization rate as developed.

Table 1 summarizes the overhead capitalization rates as reviewed by B&V.

Table 1
Overhead Capitalized
2011 and 2012 Test Years

Overhead Cost Category	2011		2012	
	Capitalization Rate (%)	Amount Capitalized ($M)	Capitalization Rate (%)	Amount Capitalized ($M)
Corporate Functions and Services	8%	$91.7	8%	$89.3
Asset Management and Operators	3%	29.8	3%	28.5
Total	**11%**	**$121.5**	**11%**	**$117.7**

Report to

Hydro One Networks Inc.

Regarding

Review of Overhead Capitalization Rates (Transmission) – 2011//2012

February 26, 2010

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SECTION I. OVERVIEW

A. Introduction

Black & Veatch ("B&V" or "we") is pleased to provide this Report to Hydro One on our *Review of Overhead Capitalization Rates (Transmission) – 2011/2012*. The Overhead Capitalization Rates ("OH Cap Rates") developed by Hydro One are percentages that are applied to the cost of Transmission and Distribution capital projects; the results are the amounts of Common Corporate Functions and Services ("CCFS") costs and AM costs that are capitalized to those capital projects for the year.

The methodology was developed for Hydro One by B&V, presented in our report *Distribution Overhead Capitalization Rate Method* report dated May 20, 2005 ("2005 Distribution Report") and accepted by the Ontario Energy Board ("OEB").

The OEB-accepted methodology to develop the OH Cap Rates has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V Review	Business Plan	B&V Report
2006 Review (Transmission)	2007-2011	*Transmission Overhead Capitalization Rate Method* dated April 30, 2006 (2006 OH Cap Report)
2008 Review (Transmission)	2009-2013	*Implementation of Transmission Overhead Rate Capitalization Methodology – 2009 / 2010* dated September 10, 2008 ("2008 OH Cap Report")
2009 Review (Distribution)	2010-2014	*Review of Overhead Capitalization Rates* dated June 29, 2009 ("2009 OH Cap-Distribution")

The calculation of Transmission OH Cap Rates for 2011-2012 is shown in Appendix A.

Hydro One computed the Transmission OH Cap Rates to be 11% for 2011 and 11% for 2012 (*Attachment A, line 78*). Based on the work we performed, B&V believes that

Hydro One's implementation of the Overhead Capitalization Rate methodology for 2011/2012 and its computation of the 2011/2012 Transmission OH Cap Rates are appropriate and conform to the OEB-accepted methodology.

B. Background

Hydro One's capital spending program is a major focus for the utility in terms of time and cost. Transmission Capital spending is budgeted to be $1,175M in 2011 and $1,177M in 2012, approximately 16% of Transmission Net utility plant annually.

Hydro One's capital program requires significant support from all areas of the utility, including engineering, management, administration and infrastructure resources. These resources support Transmission Operations and Maintenance ("OMA") and Transmission Capital Projects work.

C. Criteria for Cost Allocation Methods

The Transmission OH Cap Rate is used to distribute the Transmission portion of CCFS costs and Asset Management ("AM") costs, between Transmission OMA and Transmission Capital Projects. Following are the criteria that B&V used in selecting and evaluating methods to develop the OH Cap Rates methodology:

- The method should be based on *cost causation*.
- If cost causation can not be used or is determined to be inappropriate in the circumstances, the method usually considered next is *benefits received*.
- The method should be based on data that can be obtained at reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.
- If the method uses estimates, results should be unbiased and reasonably consistent with the results that would be obtained from using actual data.

D. Description of OH Cap Rate Method

Asset Management and Operators

The AM group is responsible for Hydro One's operating assets, including investment strategy and planning and day-to-day operation of the Ontario Grid Control Centre. Substantially all AM costs are labor and labor-related.

Hydro One performed a time study to determine the portions of AM costs devoted to Transmission capital projects, Transmission OMA, Distribution capital projects and Distribution OMA. The time study was performed for the five -week period ending April 5, 2009. AM personnel are able to determine with reasonable accuracy, on a current basis, the time they spend on each of the four areas.

A properly performed time study measures cost causation, and is widely accepted as a basis for allocating costs. B&V reviewed the Hydro One time study methodology and found it was the same as used in prior years to allocate AM time among these four areas, and was properly conducted, and therefore was a proper basis for determining the portion of AM costs capitalized to Transmission and Distribution capital projects.

Based on the time study, \$30.3 million of 2011 and \$29.0 million of 2012 AM costs are included in the amounts to be capitalized to Transmission capital projects (*Attachment A, line 69*).

Common Corporate Functions and Services Costs

Ideally, the amount of CCFS costs to be capitalized would be based on time studies for labor costs, and special studies for other costs, for each CCFS activity. However, as B&V has found in its reviews of Hydro One's Common Corporate Costs Methodology, while the CCFS departments can determine with reasonable accuracy the portions of time spent on Transmission, Distribution and the other business units, they are unable to determine with reasonable accuracy the time spent on OMA versus capital projects.

Therefore, the amount of costs to be capitalized must be computed using allocators based on cost causation or benefits received.

In traditional utility cost allocation studies, administrative and general costs are allocated based on one or more factors such as Labor costs, OMA, Investment in Plant or a weighted combination of two or more. B&V considered the following two bases for allocating CCFS costs, which are similar to administrative and general costs, between X) OMA and Y) capital projects:

- <u>Labor Content Method</u>- Labor Content of Transmission OMA versus Transmission capital projects

- <u>Total Spending Method</u>- Total Spending on Transmission OMA versus Transmission capital projects

The CCFS costs to be allocated are causally related to both Labor content and Total spending. Therefore the OH Cap Rate method for CCFS costs recommended by B&V is based on a weighting of 50% Labor Content and 50% Total Spending.

- The formula for Transmission (Tx) Labor Content is:

  Tx Labor Content = Tx Labor $ in Tx Capital Projects / (Labor $ in Tx Capital Projects + Labor $ in TxOMA)

- The formula for Tx Total Spending is:

  Tx Total Spending = Tx Capital Projects / (Tx Capital Projects + Tx OMA)

The tables below shows the results of the computation for 2011 and 2012.

Percent of Transmission CCFS Costs Capitalized	2011	2012
Labor Content- Capital	65.4%	64.1%
Total Spending- Capital	75.9%	75.4%
50/50 Average	70.7%	69.8%

Common Corporate Functions and Services Costs – Sensitivity Analysis

As a sensitivity analysis, B&V analyzed two sensitivity cases- the highest Labor Content weight considered (75%) and the lowest Labor Content weight considered (25%). The results, shown below, indicate the total OH Cap Rates would not change materially.

CASES	Labor Content / Total Spending	Transmission- 2011	
		% CCFS Costs Capitalized	OH Cap Rate
Recommended	50%/50%	70.7%	10.6%
High Labor Case	75%/25%	68.0%	10.3%
Low Labor Case	25%/75%	73.3%	10.9%
Note- In all cases Labor Content-Capital was 65.4% and Total Spending-Capital was 75.9%.			

B&V also considered the following:

1. The same rate is applied to capitalized assets regardless of their actual usage of CCFS. For example, a transformer that is purchased from a pre-approved vendor requires very little CCFS, but receives the same rate of overhead capitalization as a project requiring substantial CCFS support. In applying the OH Cap Rates, there will

be differences compared to performing a specific analysis for each project. However, the B&V method is appropriate because:

- B&V's recommended Labor / Total Content method correctly computes the total CCFS dollars to be capitalized, and the amount charged to specific projects has virtually no effect on the financial statements or on ratepayers.

- Most assets purchased for stand-alone use are Minor Fixed Assets and the OH Cap Rates are computed without them, and not applied to them. Other assets purchased are usually parts of larger projects, therefore use of the average OH Cap Rates is appropriate, because larger project are more likely to have an average usage of CCFS.

- It is impractical to perform an analysis for each project. To do so is not industry typical practice; use of an average rate is industry typical practice.

2. The OH Cap Rates are developed based on the weighted Labor Content and Total Spending, but are applied to Total Capital Cost.

It is appropriate to compute the total costs to be capitalized based on the weighted Labor Content / Total Spending. Once the amount to be capitalized is computed, it can be applied based on either Total Cost or Labor Content. B&V recommends stating the capitalization rate based on Total cost, and applying it to Total cost dollars, as Hydro One has done, because it is easier to plan and implement based on Total cost than Labor content. In addition, this is the industry typical practice.

B&V believes that allocating CCFS costs to capital projects based on 50% Labor Content / 50% Total Spending is the most appropriate method for Hydro One, and is consistent with industry practice and with the nature of the CCFS costs being capitalized.

SECTION II. COMPUTATION OF TRANSMISSION OH CAP RATE USING RECOMMENDED METHOD

In this Section we will present the computation of the Transmission OH Cap Rate for 2011. The Transmission OH Cap Rate for 2012 uses the same method.

A. Formula

The following formula is used by to compute the Transmission OH Cap Rate for 2011:

Transmission OH Cap Rate=(Transmission CCFS Cap +Transmission AM Cap) /Transmission Capital

Where

Transmission_AM_Cap= AM costs capitalized to Transmission capital projects

Applicable Transmission CCFS costs = Transmission CCFS costs subject to capitalization

Transmission Capital = Cost of Transmission capital projects supported by CCFS and AM; also, total cost of Transmission capital projects to which the Transmission OH Cap Rate is applied

Transmission CCFS Cap = Transmission CCFS costs capitalized = (Transmission Labor Content X 50% + Transmission Total Spending X 50%) X Applicable Transmission CCFS Costs

Transmission Labor Content = Transmission Labor $ in Transmission Capital Projects / (Labor $ in Transmission Capital Projects + Labor $ in Transmission OMA)

Transmission Total Spending = Transmission Capital Projects / (Transmission Capital Projects + Transmission OMA)

These terms are further discussed below.

B. Recommended Method

This section discusses the method recommended by B&V to compute the Transmission OH Cap Rate. References below are to Appendix A, using amounts for 2011. The calculation uses projected data. Because the methodology includes a true-up (page 11), any continuing effect of the difference between actual and projected amounts will be not significant.

1) Transmission Capital
(Appendix A, rows 1-8)

Transmission Capital represents the cost of Transmission business Capital Projects that are supported by Transmission business CCFS activities and AM activities, and is the total cost of Transmission business Capital Projects to which the Transmission OH Cap Rate is applied. Transmission Capital equals total spending for Transmission Capital Projects reported for financial accounting, adjusted as follows:

- Minor Fixed Assets (such as vehicles) and Interest Capitalized are removed because they require little CCFS or AM support. Capitalized Overhead is removed to avoid redundancy.

- Capital Contributions by Customers are added because the CCFS or AM effort required is related to gross capital cost, not net capital cost. Removal Costs are added because removal of capital assets requires CCFS or AM effort.

2) Transmission Spending for OMA
(Appendix A, rows 10-16)

Transmission Spending for OMA is used in computing the portion of Total Spending (capital plus OMA) related to capital (rows 37-41). The amounts are based on the

Updated BP 2010-14, with adjustments to remove those costs which are included in Applicable CCFS Costs (row 29).

3) Applicable Transmission CCFS costs
(Appendix A, rows 18-29)

Applicable Transmission CCFS represents the Transmission CCFS costs that are subject to capitalization, and equals the amount of CCFS costs distributed to the Transmission unit in the Common Corporate Cost Model Exhibit C1, Tab 6, Schedule 1 *(Row 19)*, adjusted as follows:

- The Transmission Facilities costs that are removed from the CCFS costs, relating to Operations facilities, are added back.
- The portion of Transmission CCFS costs representing operating-type costs is removed because these departments do not support OMA or capital projects. These activities include Inergi- Customer Support Operations (CSO), Inergi- Settlements, Inergi-ETS costs to support CSO Applications and Inergi-ETS costs to support market transition costs.

4) Transmission Labor Content- Capital
(Appendix A, rows 31-35)

Transmission Labor Content-Capital is the portion of total Transmission labor costs included in Transmission Capital Projects. The computation uses the formula:

Transmission Labor Content = Transmission Labor $ in Transmission Capital Projects / (Labor $ in Transmission Capital Projects + Labor $ in Transmission Operations and Maintenance)

The Labor $ on Rows 32-33 were developed by Hydro One. The Labor $ are fully burdened labor costs.

5) Transmission Total Spending- Capital

(Appendix A, rows 37-41)

Transmission Total Spending-Capital is the portion of Transmission total spending is included in Transmission Capital Projects. The computation uses the formula:

Transmission Total Spending = Transmission Capital Projects / (Transmission Capital Projects + Transmission Operations and Maintenance)

Transmission spending for OMA (row 38) is from row 16. Transmission spending for capital projects is from row 8.

6) Transmission CCFS Cap

(Appendix A, rows 37-51)

The average of the Transmission Labor Content-Capital (from row 35) and the Total Spending- Capital (from row 41), using the appropriate weights (rows 44-45), is the capitalized portion of CCFS costs (row 47). This portion is multiplied by the Applicable CCFS costs (row 49, from row 29) to compute Capitalized CCFS costs (row 51).

7) Transmission AM Cap

(Appendix A, rows 53-69)

Transmission AM Cap represents the amount of AM costs capitalized to Transmission business Capital Projects. The time study performed by Hydro One for the five weeks ended April 5, 2009 showed that 24.3% of AM Non-operator time, 24.8% of Operator time and 0.1% of Customer Care time, are related to Transmission Capital Projects. These percentages are applied to the Updated BP 2010-14 annual budgeted amounts for AM, and the results are the amounts of AM costs to be capitalized (row 69).

8) E-Factor

Hydro One trues up the Transmission OH Cap Rate to actual at the end of each fiscal year, therefore an E-factor (to reflect the difference between A) the amount of CCFS and AM costs actually capitalized for a prior year and B) the amount that would have been capitalized for that year using actual data instead of estimates in OH Cap Rate calculation) is no longer needed or used.

9) Transmission OH Cap Rate

(Appendix A, rows 71-78)

The Transmission OH Cap Rate equals A) the sum of items 6) and 7) above, divided by B) Capital spending. The Transmission OH Cap Rate for 2011 is **11%** (row 78).

TRANSMISSION OVERHEAD CAPITALIZATION RATE

	($ millions)	2011	2012
1	**Capital Expenditures**		
2	Total capexp	1,263.0	1,263.9
3	Less: Minor fixed assets	(33.8)	(24.2)
4	Less: Capitalized overhead	(129.3)	(128.1)
5	Less: Capitalized interest	(61.2)	(59.2)
6	Add: Capital contributions	118.0	107.0
7	Add: Removal costs	18.4	18.1
8		1,175.0	1,177.5
9			
10	**OM&A**		
11	Total OM&A	455.6	469.8
12	Less: CCFS costs	(113.3)	(126.9)
13	Less: Facility costs	(21.9)	(12.2)
14	Less: Asset Management costs (excl. facility costs)	(76.6)	(74.2)
15	Add: Capitalized overheads	129.3	128.1
16		373.0	384.6
17			
18	**Capitalized CCFS Costs**		
19	CCFS Costs	113.3	126.9
20	Add: Facility costs	21.9	12.2
21			
22	Less operating-type CCFS costs:		
23	Inergi - CSO	-	-
24	Inergi - ETS CSO Apps	-	-
25	Inergi - ETS Market Ready	(1.3)	(1.3)
26	Inergi - Settlements	(0.5)	(0.7)
27		(1.7)	(2.0)
28			
29	Applicable CCFS costs	133.5	137.1
30			
31	Portion capitalized based on labour content:		
32	Labour in OM&A	210.5	225.3
33	Labour in capexp	398.3	402.7
34		608.7	628.0
35	% capexp	65.4%	64.1%
36			
37	Portion capitalized based on total spending:		
38	OM&A	373.0	384.6
39	Capexp	1,175.0	1,177.5
40		1,548.0	1,562.1
41	% capexp	75.9%	75.4%
42			
43	Weighting:		
44	Labour content	50.0%	50.0%
45	Total spending	50.0%	50.0%
46			
47	Capitalized based on weighting of two methods	70.7%	69.8%
48			
49	Applicable CCFS costs	133.5	137.1
50			
51	Capitalized CCFS costs	94.3	95.6
52			

TRANSMISSION OVERHEAD CAPITALIZATION RATE

	($ millions)	2011	2012
53	**Capitalized Asset Management Costs**		
54	Network Asset Management Costs (Tx + Dx):		
55	Asset Management (excl. facility costs)	85.7	80.2
56	Operating	45.6	45.7
57	Customer Care Management	13.3	20.5
58		144.7	146.4
59			
60	Portion capitalized (per time study):		
61	Asset Management (excl. facility costs)	24.3%	24.3%
62	Operating	20.8%	20.8%
63	Customer Care Management	0.1%	0.1%
64			
65	Capitalized Asset Management costs:		
66	Asset Management (excl. facility costs)	20.8	19.5
67	Operating	9.5	9.5
68	Customer Care Management	0.0	0.0
69		30.3	29.0
70			
71	**Overhead Capitalization Rate**		
72	Capitalized CCFS costs	94.3	95.6
73	Capitalized Asset Management costs	30.3	29.0
74		124.7	124.6
75			
76	Capexp	1,175.0	1,177.5
77			
78	**Calculated overhead capitalization rate**	**11%**	**11%**

COMMON ASSET ALLOCATION

1.0 INTRODUCTION

This evidence will discuss the nature of Common Fixed Assets ("Shared Assets") and the method by which the costs of these assets are assigned to the Transmission and Distribution business units.

Similar to the common corporate costs discussed in Exhibit C1, Tab 5, Schedule 1, Hydro One has been able to maximize efficiencies through the centralization of the maintenance, management and purchase of shared assets at the corporate level. These assets include shared land and buildings, telecommunication equipment, computer equipment, applications software, tools and transportation and work equipment (“T&WE”).

2.0 SHARED ASSETS AND FACILITIES COSTS

Most fixed assets are directly assigned to the appropriate business unit. The remaining assets (4% of total assets) are considered shared assets, and are allocated to Transmission and Distribution as described later in this exhibit. Table 1, below, summarizes the total gross fixed assets and identifies the proportion of allocated shared assets.

Table 1
Summary of Gross Fixed Assets
as at December 31, 2008 ($ Million)

	Transmission	Distribution	Total
Total Fixed Assets	10,477.8	6,591.5	17,069.2
Shared Assets (in Total)	339.6	510.5	850.2
Shared Asset %	39.9%	60.1%	100%

Shared assets are sub-divided into two categories. Major Fixed Assets consist of land, buildings, applications software, and telecommunications equipment. Minor Fixed Assets include office furniture, computer equipment, tools and T&WE. Table 2, below, shows the proportion of major and minor shared fixed assets, accumulated depreciation and net book value as of December 31, 2008.

Table 2
Details of Shared Net Fixed Assets
as at December 31, 2008 ($ Million)

Asset	Gross Asset Value	Accumulated Depreciation	Net Book Value
Shared Major Assets	352.7	135.2	217.5
Shared Minor Assets	497.5	268.8	228.7
Total Shared Assets	**850.2**	**404.0**	**446.1**

3.0 ALLOCATION OF SHARED ASSETS IN SERVICE

Due to the nature of Hydro One's business, shared assets are not directly attributable to either the Transmission or Distribution business units. In addition, from year to year, the use of these shared assets may change, based upon changes in the underlying transmission and distribution work programs. Consequently, the methodology by which shared assets are allocated to the Transmission and Distribution business units is subject to periodic review. The intent of such a review is to ensure that the assignment of assets is reflective of their use and that the costs are apportioned appropriately amongst the business units.

In 2008, the Company commissioned a study by Black & Veatch (B&V) (Formerly R.J. Rudden Associates) to determine a methodology to allocate the assets which are not directly attributable to Transmission or Distribution. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The B&V study resulted in the allocation of shared assets based on the relative usage by Transmission and Distribution or by cost drivers, similar to those used for the common corporate functions and services.

The Company has accepted the approach of the B&V study as a reasonable representation of the use of shared assets amongst the business units. This methodology was utilized and subsequently endorsed by the Board in the previous Distribution rate Decision EB-2007-0681 and Transmission rate Decision EB-2008-0272.

The appropriate use of the common asset allocation methodology for the 2011 and 2012 test years has been reviewed and confirmed by B&V in 2009, and is provided as Attachment 1 to this Exhibit.

Hydro One has used the approved B&V Asset Allocation methodology in this application and Table 3 below shows the Hydro One Common Asset allocation as at December 31, 2008.

Table 3
Hydro One Common Asset Allocation
as at December 31, 2008 ($ Million)

Total Gross Value All Hydro One Transmission & Distribution Assets $17,069 million			
Transmission (Total)	$10,478	Distribution (Total)	$6,592
Transmission (Direct)	$10,138	Distribution (Direct)	$6,081
Transmission (Common)	$340	Distribution (Common)	$511

Report to

Hydro One Networks Inc.

Regarding

Review of Common Assets Allocation (Transmission) – 2010

February 26, 2010

TABLE OF CONTENTS

SECTION I. SUMMARY

A. Background and Purpose

Black & Veatch ("B&V" or "we") is pleased to submit this Report on our Review of Common Assets Allocation (Transmission) – 2010 to Hydro One Networks Inc. This Report describes the review that B&V performed, at the request of Hydro One, of Hydro One's allocation of the costs of Common Assets in its 2011/2012 Transmission Rates filing before the Ontario Energy Board ("OEB"). In this Report, "cost" is as of December 31, 2008.

In 2005, B&V recommended, Hydro One adopted, and the OEB accepted a methodology for Hydro One to allocate the costs of Common Assets between its Transmission business and Distribution business, and issued our *Report on Shared Assets Methodology Review* dated June 15, 2005 ("2005 Assets Report"). B&V's objective in allocating the Common Assets was to ensure that the allocation was reasonable and was consistent with the allocation of the costs of the common corporate functions and services, as discussed in our *Review of Shared Services Costs Methodology – 2010* dated February 26, 2010 ("2010 Shared Costs Report)".

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V Review	Asset Values	B&V Report
2006 Review	12/31/2005	*Report on Common Assets Methodology 2006* dated May 31, 2006 ("2006 Assets Report")
2008 Review	12/31/2007	*Report on Common Assets Methodology 2008* dated September 10, 2008 ("2008 Assets Report")
2009 Review (Distribution)	12/31/2008	*Report on Common Assets Allocation- 2009* dated June 29, 2009 ("2009 Assets Report-Distribution")

The OEB-accepted methodology has been applied by Hydro One to its Updated Business Plan ("BP 2010-2014") data for its 2011/2012 Transmission Rates filing. This Report describes the Review of Common Assets Allocation (Transmission) – 2010 that B&V performed, at Hydro One's request, of Hydro One's application of the methodology to its BP 2010-2014, and B&V's conclusion.

In its 2011/2012 Transmission Rates filing, Hydro One has allocated 40.1% of the costs of the Common Assets to the Transmission business, the same percentage allocated in its 2010/2011 Distribution Rates filing.

No Common Assets are allocated to the Telecom and Remotes businesses, because these amounts would be very small.

B. Types of Common Assets

Hydro One provided B&V with a list of the Common Assets, grouped by Asset Group and Component. The Asset Groups and Components are shown in Table 1.

TABLE 1 TYPES OF COMMON ASSETS

Asset Group	Components
Major Assets	• Software • Buildings and Telecommunications equipment
Minor Fixed Assets ("MFA")	• Aircraft • Computer Hardware • Office equipment • Service equipment- Miscellaneous • Service equipment- Measurement and Testing • Service equipment- Storage • Tools
Transportation Work Equipment ("TWE")	• Transportation Work Equipment • Transportation Work Equipment- Power equipment

C. Summary of Approach

Our approach was to allocating the costs of Common Assets was:

- For each asset, B&V discussed with Hydro One personnel if it was possible to estimate its relative usage by Distribution and Transmission.

- If it was possible to estimate the relative usage, the cost of the asset was allocated based on the estimated usage. B&V reviewed the usage estimates to ensure that similar assets were classified consistently. Assets estimated to be used at least 95% in either Distribution or Transmission, were 100% assigned to that business and removed from Common Assets.

- If it was not possible to estimate the relative usage of an asset, a cost driver was assigned based on discussions with Hydro One personnel, to ascertain what cost driver was most closely related to usage. The cost drivers used to allocate the Common Assets were selected from among, or derived from, the cost drivers used to allocate the costs of the common corporate functions and services.

The specific steps used for each Asset Group are discussed below. The results are summarized in Table 2.

SECTION II. DESCRIPTION OF EACH ASSET GROUP

A. Major Assets

Software

Most of the software included in Common Assets was for Hydro One's Cornerstone project, an enterprise-wide system that will eventually replace existing systems that support work management, asset management, human resources, financial and other functions. Cornerstone Phase 1, which was in use at Dec. 31, 2008, was allocated using a cost driver that reflects the activities it supports. Costs for PeopleSoft and related work management software were also allocated using the Cornerstone Phase 1 cost driver, because these systems were replaced by Cornerstone in 2010.

Software used to manage real properties was allocated using the costs of the Real Estate department that was developed in the Common Corporate Costs study.

Buildings and Telecommunications equipment

Each asset included in Buildings and Telecommunications Common Assets was discussed with Hydro One personnel, and allocated using one of the following methods:

- Specific estimation for a building. For example, Sudbury Service Centre has estimated usage of Distribution-80% / Transmission-20%.

- Allocation based on type of usage. For example, Hydro One performed an analysis of Fleet time charges for the years 2006 2008 and determine that Fleet usage is: Distribution- 76%, Transmission- 23% and Remotes- 1%, therefore the costs for buildings used for Fleet were allocated using these percentages. Buildings used for Training were allocated based on FTEs (full-time equivalent employees).

- Cost drivers based on usage. For example, Buildings used to manage both Distribution and Transmission projects were allocated using the

ProgramProjectCosts cost driver developed in the Common Corporate Costs study.

B. Minor Fixed Assets

Each component of Minor Fixed Assets Common Assets includes many individual items. B&V reviewed the lists of individual items and determined the following allocations to be appropriate:

Aircraft – Helicopter components. Usage was based on an analysis of activity for the years 2006 to 2008.

Computer Hardware – Includes Laptops, Desktops, Network equipment, Printers, etc. Allocated using cost driver based on number of *Workstations* (50% weight) and number of *FTEs* (50% weight).

Office equipment – Includes office furniture and other office equipment. Allocated using cost *FTEs*.

Service equipment - Miscellaneous – Includes miscellaneous equipment. Allocated using the *Total CCFS* cost driver developed in the Common Corporate Costs study.

Service equipment- Measurement and Testing – Includes Meters, Splicers etc. used for Distribution. Directly assigned to *Distribution*.

Service equipment- Storage – Includes Waste Storage and Other Storage equipment. Allocated using cost driver based on spending for *Operating and Maintenance costs and Capital spending*.

Tools – Includes Rental tools. Allocated Distribution-20% / Transmission-80% based on estimated usage.

The results are summarized in Table 2.

C. Transportation & Work Equipment

Approximately 94% of Transportation & Work Equipment Common Assets were allocated using the cost driver Fleet, and was allocated based on the analysis performed by Hydro One discussed above. The balance were directly assigned to Distribution or Transmission based on usage. The results are summarized in Table 2.

SECTION III. SUMMARY OF RESULTS

The results for of the Common Assets allocation are summarized in Table 2.

TABLE 2 SUMMARY OF COMMON ASSETS ALLOCATION (YEAR - END 2008 - $ MILLIONS COST)					
(C$000)	**Total**	**Trans-mission**	**Distrib-ution**	**Trans-mission%**	**Distrib-ution %**
Major Assets					
Software	$245.1	$137.1	$108.0	55.9%	44.1%
Building / Telecom	70.7	38.5	32.2	55.4%	45.6%
Total	315.8	175.6	140.2	55.6%	44.4%
Minor Fixed Assets					
Aircraft	17.8	12.0	5.8	67.6%	32.4%
Computer Hardware	70.4	37.3	33.1	53.0%	47.0%
Office Equipment	6.2	3.3	2.9	53.0%	47.0%
Service- Misc.	5.6	2.4	3.2	42.8%	57.2%
Service- Measure/Test	5.9	-	5.9	-	100.0%
Service- Storage	8.0	4.5	3.5	56.6%	43.4%
Tools	5.7	4.6	1.1	80.0%	20.0%
Total	119.6	64.1	55.5	53.6%	46.4%
Transportation Work Equipment					
Total	377.9	86.2	291.7	22.8%	77.2%
Total - All Common Assets	$813.3	$325.9	$487.4	40.1%	59.9%

DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and amount of Hydro One Transmission's depreciation and amortization expense for the 2011 and 2012 test years.

The depreciation and amortization expense for Hydro One's submission for 2007 and 2008 Electricity Transmission revenue requirements (EB-2006-0501) was supported by an independent study conducted by Foster Associates Inc. (Foster), completed in June, 2006. In EB-2008-0272, Hydro One submitted a 2008 Technical Update conducted by Foster completed in August 2008 that supported the 2009 and 2010 depreciation and amortization expense. The Board accepted the costs flowing from the Depreciation Study for the purpose of supporting Transmission rates in those years.

The depreciation and amortization expense for 2011 is $302.9 million and for 2012 is $334.8 million.

2.0 DEPRECIATION EXPENSE

In accordance with the Board's Decision (EB-2006-0501), Hydro One Transmission used the Foster methodology for determining the depreciation rates currently in use.

The depreciation expense for 2011 is $295.5 million and for 2012 is $326.9 million.

Detailed depreciation schedules are filed at Exhibit C2, Tab 4, Schedule 1.

Table 1
Transmission Depreciation Expense
$ Million

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Depreciation On Fixed Assets	214.4	225.5	243.4	263.9	286.3	317.6
Less Capitalized Depreciation	(6.4)	(8.0)	(12.2)	(8.4)	(9.2)	(8.8)
Asset Removal Costs	11.2	14.1	10.1	17.7	18.4	18.1
Losses/(Gains) On Asset Disposition	(1.0)	0.1	(2.3)	0.0	0.0	0.0
Total	**218.2**	**231.7**	**239.0**	**273.1**	**295.5**	**326.9**

3.0 AMORTIZATION EXPENSE

Amortization expense addresses the recovery of costs the Board has allowed Hydro One Transmission to defer to a future date. The Board has, in past decisions, approved the deferred balance and the prescribed method and time period for which the costs in each account may be recovered.

Amortization schedules for test, bridge and historical years are filed at Exhibit C2, Tab 4, Schedule 1. Table 2, below, reproduces this summary.

Table 2
Transmission Amortization Expense ($ Million)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Other Post Employment Benefits (OPEB)	17.9	17.9	0.0	0.0	0.0	0.0
Environmental Assets and Other	5.4	3.7	2.5	5.6	8.4	8.9
Total	**23.3**	**21.6**	**2.5**	**5.6**	**8.4**	**8.9**

3.1 Environmental Assets and Other

Hydro One Transmission provides for estimated future expenditures required to remediate past environmental contamination and to comply with current environmental legislation. Since these expenditures are expected to be recovered in future rates, Hydro One Transmission has recognized the net present value of these estimated future expenditures as a regulatory asset. The balance is amortized on a basis consistent with the pattern of current expenditures expected to be incurred up to the year 2018. Hydro One Distribution received approval for this deferral account as part of the OEB's RP2000-0023 Decision. Hydro One Transmission's treatment of these costs in its Application for 2007-2008 Transmission Rates (EB-2006-0501) was consistent with that Decision and was accepted by the Board. The treatment of these costs in this Submission is consistent with that in both prior proceedings.

Expenditures, and resulting amortization expense, for Hydro One Transmission's environmental programs are expected to increase over historical levels as a result of recent external regulatory changes. Specifically, Environment Canada's final regulations for the management and disposal of polychlorinated biphenyls ("PCBs") will have the result of increasing PCB compliance expenditure, while recent Ontario brownfield regulations will have the impact of increasing land assessment and remediation expenditures.

PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

1.0 INTRODUCTION

Under the *Electricity Act, 1998*, Hydro One Networks Inc. ("Networks") is required to make payments in lieu of corporate income taxes ("PILs") relating to taxable income earned by its transmission business. The Board has directed that the taxes payable method should also be used for regulatory purposes, according to its 2006 EDR Handbook, Section 7.1 "OEB 2006 Regulatory Taxes Expense Methodology".

Under the taxes payable method, no provision is made for future income taxes that result from timing differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, the taxes payable method will result in the PILs income tax payable being different from the amount that would have been recorded, had the combined Canadian Federal and Ontario statutory income tax rate been applied to the regulatory net income before tax. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the Board and recovered from customers at that time.

PILS installments are remitted by Networks to the OEFC at the end of each month. Any balance owing at the end of the year is required to be paid by February 28th of the following year.

In the absence of an Electricity Transmission Handbook, the 2011 and 2012 Hydro One transmission regulatory tax calculations have been prepared consistent with the approach found in the 2006 EDR Handbook and the 2006 EDR Tax Model, as this approach reflects the tax payable relating to taxable income earned by the transmission business.

2.0 INCOME TAX RATE (FEDERAL AND ONTARIO)

For the test years, a combined income tax rate of 28.25% has been used for 2011 and 26.25% for 2012 (The 2011 rate comprises a Federal rate of 16.50% and an average Ontario rate of 11.75%. The 2012 rate comprises a Federal rate of 15% and an average Ontario rate of 11.25%). This reflects the reductions in the Federal and Ontario income tax for corporations (enacted on December 13, 2007 and November 16, 2009 respectively). The Board's May 28, 2009 Decision (EB-2008-0272) respecting Hydro One Transmission's 2009 and 2010 Revenue Requirements approved a combined income tax rate of 33 % for 2009 (comprising a Federal rate of 19% and an Ontario rate of 14%) and a combined rate of 32% for 2010 (comprising a Federal rate of 18% and an Ontario rate of 14%). Any variance between actual taxes payable and forecast taxes, as a result of rate changes for income tax or capital cost allowance will be captured in a deferral account for tax rate changes, discussed further in Exhibit F, Tab 2, Schedule 1.

3.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

A reconciliation between the regulatory net income before tax ("NIBT") and taxable income for the test years 2011 and 2012 is provided in Exhibit C2, Tab 5, Schedule 1. This schedule contains the income tax component of the PILs computation. It also shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation and capital cost allowance (CCA).

A reconciliation between the accounting NIBT and taxable income for the historical years is also provided in Exhibit C2, Tab 5, Schedule 1**.** This reconciliation entails adjustments to regulatory NIBT to arrive at taxable income. In order to make it easier for parties to follow these reconciliations, Hydro One Transmission has placed these adjustments into the following five categories:

1) Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement, or for which appropriate tax adjustments are made (for example, depreciation versus CCA);
2) Deferral accounts not included in the revenue requirement;
3) Reversal of accounting adjustments not included in the revenue requirement;
4) Recurring items not in the revenue requirement; and
5) Items whose impact is immaterial in total, and as such, have not been included in the Company's business plan (applicable to forecast years only).

4.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of Hydro One Transmission's taxable income is the NIBT as shown on the utility's income statement for the year. The NIBT is prepared using Canadian Generally Accepted Accounting Principles, but taxable income is computed using the relevant tax legislation, interpretations and assessing practices. Therefore, many adjustments are typically made to the NIBT to arrive at taxable income. Essentially, the NIBT is increased by amounts that are not deductible for tax purposes. This includes items such as depreciation, contingent liabilities, accounting losses, accounting provisions such as other post employment benefits ("OPEB") and revenue that has been received but not recognized for accounting purposes (for example, transmission export revenue). On the other hand, the NIBT is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT. This includes items such as CCA, the deductible portion of capitalized overhead, accounting gains and OPEB payments. Such reductions also include expenses incurred for which a deferral account has been set up on the balance sheet, rather than shown as a deduction through the income statement.

Consequently, it is imperative that the NIBT be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes. This is a key point in comparing the historical years tax return data to that computed for the forecast years, since the tax return NIBT has been increased (or reduced) by amounts that have not been added (or deducted) in computing the regulatory NIBT (e.g. contingent liabilities, accounting gains, capitalized interest). That is, for test years 2011 and 2012, adjustments for differences between the tax and accounting rules only (related to costs included in either the regulatory revenue requirement or rate base, such as CCA or capitalized overhead), are made to arrive at taxable income.

5.0 TAX TREATMENT OF DEFERRAL ACCOUNTS (REGULATORY ASSETS AND LIABILITIES)

Deferral accounts are typically recognized by utilities' balance sheets for foregone revenue or for expenses that have been incurred, for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the Board.

For example, as shown in Table 1, assuming that a $100 expense is incurred, the utility will be allowed to deduct the $100 in computing taxable income for the year in which the expense has been incurred. If the Board subsequently approves recovery of this expense over a 2-year period through a rate rider, the income will be included in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income or expense has been taxed or deducted in different years.

Table 1

	Year 1	**Year 2**	**Year 3**	**CUM**
Income (deduction)	(100)	50	50	Nil
Tax Refund (payable)	31	(15.5)	(15.5)	Nil
Cash Inflow (outflow)	(69)	34.5	34.5	Nil

Therefore, deferral accounts have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. It should be noted that this conclusion is consistent with the "2006 EDR Handbook Report of the Board" issued May 11, 2005 (page 61) that stated as follows:

> "A PILS or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their returns. The Handbook will reflect this treatment."

6.0 CONTINGENT LIABILITIES/ACCOUNTING RESERVES

Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future (such as obsolescence provisions, lawsuits, staff reductions), the provision will reduce the NIBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed by the utility for reasonableness based upon the information available at that time. The balance may be adjusted upward or downward, with NIBT either decreasing or increasing, respectively.

However, for tax purposes, a contingent liability or accounting reserve is not deductible. Rather, the amount will only be deductible (or capitalized) in computing taxable income for the taxation year in which the obligation has actually been settled. Therefore, to the extent that the current year NIBT has been increased (or decreased) by the contingent liability or accounting reserve provision, the NIBT must be adjusted to reverse the increase (or decrease) in computing taxable income.

It is not necessary to adjust the 2011 and 2012 NIBT for contingent liabilities in computing taxable income since no changes were forecast in the contingent liability balances for 2011 and 2012. Therefore, such amounts are not included in the tax computation for purposes of the revenue requirement.

In summary, the projected net income before tax for the test years is higher than the 2008 historic year which is primarily driven by the increase in rate base. This is consistent with our higher level of PILs payable for the test years relative to the 2008 historic year as shown in Exhibit C2, Tab 1, Schedule 1. The increases mentioned above are partially offset by lower income tax rates in test years.

The combined (Federal and Ontario) enacted income tax rates are as follows:

2007	36.12%
2008	33.5%
2009	33%
2010	31%
2011	28.25%
2012	26.25%

7.0 ONTARIO CAPITAL TAX

As of July 1, 2010, the Ontario capital tax is eliminated. Therefore there is no Ontario capital tax calculated for the 2011 and 2012 test years.